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Via: email
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Public Utility Commission of Oregon
Filing Center
201 High Street SE, Ste. 100
P.O. Box 1088
Salem, OR 97301-1088

RE: UE 335 2019 Net Variable Power Cost - Reply Testimony

Submitted for filing is Reply Testimony and Exhibits of Portland General Electric Company

- Exhibit 1400 filed electronically
- Non- confidential exhibits 1401 & 1404 filed electronically
- Confidential exhibits 1402C & 1403C Fed-ex to PUC in electronic format
- Non-confidential workpapers submitted to Huddle
- Confidential workpapers submitted to Huddle

If you have any questions or require assistance please call me at (503) 464-7805. Please direct all formal correspondence and requests to pge.opuc.filings@pgn.com.

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

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I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis.

My name is Cathy Kim. My position at PGE is General Manager, Power Operations.

My name is Greg Batzler. My position at PGE is Senior Regulatory Analyst, Rates and Regulatory Affairs.

Our qualifications were previously provided in PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the positions the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens' Utility Board (CUB) regarding PGE's net variable power cost (NVPC) forecast for 2019.

Q. Please summarize your review of parties' positions.

A. Parties have introduced positions on several issues. In almost all instances, parties recommend reductions to PGE's NVPC forecast. As described in more detail below, we largely believe parties' positions are (1) inaccurate, (2) opportunistic in seeking benefits (without recognizing costs or risks), (3) based on incomplete analysis, or (4) revisit previous decisions bordering on retroactive ratemaking. If implemented in their entirety, parties' recommended reductions would unfairly introduce a significant downward bias on PGE's NVPC forecast, making it highly unlikely PGE would recover prudently incurred power costs in 2019 under normal conditions.

Q. How does the total amount of parties' proposed adjustments compare to PGE's current NVPC forecast?

A. The combined sum of the adjustments proposed by Staff and AWEC total approximately $43.9 million. This compares to PGE's March 30 forecast of NVPC of approximately $379.6 million, or approximately 11.6% of PGE's 2019 forecasted NVPC.

Q. What is your recommendation regarding the specific issues identified below?

A. With certain exceptions that we discuss below, we recommend the Commission reject AWEC's and OPUC Staff's proposed adjustments.

Q. What specific issues do you address in your testimony?

A. We address the following issues raised by parties:

- **Western Energy Imbalance Market (EIM**) **(Section II-A)**: Staff proposes using historical results as the basis for setting Western EIM benefits, however, with less than a full year of actual results, it is simply too early to begin using actual results as the basis of a normalized NVPC forecast.
- **California-Oregon Border (COB) Trading Margins (Section II-B):** Staff proposes a methodology for valuing California trading margins, using non-relevant and inconsistent data to calculate a "COB transaction value per dollar of margin," resulting in artificially inflated hypothetical COB gains based on MWh volumes that are, at times, five times larger than our AC southbound and northbound transmission rights. Additionally, Staff's methodology produces a result that is highly volatile. For example, using the February 15, 2018 forward curve, Staff's method calculates approximately $23 million of gross benefit. But, if updated with the market forward

curves for PGE's forthcoming July 6 update filing, Staff's method yields less than $1 million of gross benefit.

- **Wind Capacity Factors (Section II-C):** Both Staff and AWEC use an incomplete and inaccurate historical record to propose a punitive adjustment to PGE's wind capacity factor forecast, which is inconsistent with the treatment of other owned resources or power purchase agreements. Finally, Staff's and AWEC's proposals ignore costs PGE has absorbed due to lower than forecast wind production, and their proposals do not result in a more accurate forecast of wind energy generation.
- **Market Price Forecasting (Section II-D):** AWEC's proposal to adjust the market forward prices used in MONET and to share PGE's hedging costs and benefits is based on hindsight and flawed analyses, ignores long-standing, consistent, and thoroughly reviewed practices, and attempts to deny PGE recovery of prudently incurred costs.
- **Production Tax Credits (PTCs) (Section II-E):** PGE proposes to modify AWEC's proposal of increasing the PTC rate. In addition, PGE provides evidence that customers are receiving a full 10 years of Biglow 2 PTC benefits.
- **Carty Lateral Costs (Section II-F):** Staff's conclusion that Carty could have been supplied gas using a 16" pipeline with no compression is based on both flawed analysis and assumptions. The fact is that, at the time the decision was made to size the lateral pipeline, the 20-inch pipeline was the least cost/least risk option and an appropriate and prudent decision.
- **Qualifying Facilities (Section II-G):** PGE appreciates Staff's agreement with our requested methodology and finds Staff's recommendations reasonable. Both AWEC

and CUB rely on the methodology approved by the Commission for PacifiCorp and Idaho Power[1] as their primary reason for rejecting PGE's proposal. Their recommendation ignores PGE's history with Qualifying Facilities compared to both PacifiCorp and Idaho Power and that PGE's proposal provides the simplest, most straightforward, and most accurate method for ensuring that accurate online delivery dates are properly reflected in customer prices.

- **North Mist Expansion Project (Section II-H-1):** Staff's recommendation on adjusting the final forecast of the North Mist Expansion Project in-service date represents a reasonable request that PGE can accommodate.
- **BPA Wheeling Rates (Section II-H-2):** AWEC's recommendation that PGE should not escalate the BPA wheeling rates is based on the anomalous outcome of BPA's 2018 rate case (BP-18), which resulted in a reduction in BPA Point-to-Point (PTP) transmission rates. This ignores the fact that, although BPA PTP rates were reduced in BP-18, the Scheduling, System Control, and Dispatch (SCD) rates were increased, resulting in an overall wheeling rate increase. Additionally, PGE's current forecast is based the average PTP rate increase for the last eight BPA transmission rate cases. For these reasons, we believe our forecast is appropriate at this time.
- **Code Review (Section II-H-3):** PGE has reached out to CUB with a proposal regarding this issue. We discuss our proposal below as well as highlight some key issues that must be addressed prior to any potential code review being conducted.
- **Capacity Agreements (Section II-H-4):** Staff's recommendation to exclude the incremental cost of PGE's 2019 capacity contract resulting from Docket No.

[1] See Commission Order No. 17-444 in Docket No. UE 323.

UM 1892 ignores the thorough review of this contract conducted by Staff and other stakeholders within UM 1892. Staff has stated that they need to review the financial analysis. PGE will provide Staff access to the financial analysis concluding that this contract met PGE's requirements from both a least cost and least risk perspective.

- **Headwater Benefit Study (HWBS) (Section II-H-5):** Staff is continuing to review the material PGE provided in support of the proposed change to the 2019 NVPC forecast associated with correcting and including the results of the 2016-2017 HWBS. PGE will update its July NVPC filing with the corrected 2016-2017 HWBS, consistent with the information provided to Staff on May 23, 2018.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have two sections:

- Section II: Parties' Proposed Adjustments
- Section III: Summary and Conclusion

II. Parties' Proposed Adjustments

A. Western EIM

Q. Please summarize Staff's proposal regarding Western EIM benefits and costs.

A. Staff proposes to use a forecast based on historical data, preferably 12 months of actual results from PGE's participation in the Western EIM. Staff believes the use of historical data is reasonable, because Staff believes that PGE's current forecast is unreasonably low.

Q. Do you agree with Staff's proposal?

A. No. While PGE's transition into the Western EIM has gone smoothly, it is simply too early to begin using actual results from PGE's participation in the Western EIM as the basis for a forecast of PGE's Western EIM benefit. The end of May 2018 marks PGE's eighth month of participation in the Western EIM.[2] Eight months of results is a very limited amount of data that does not represent even a single year, and is not a reasonable basis to estimate Western EIM benefits. More months are required to identify what "normal" benefits would be, or to identify outliers or other drivers of benefits that are not ongoing or representative of average conditions.

Q. What is the amount of Western EIM benefit proposed by PGE in its NVPC forecast?

A. PGE proposes a direct Western EIM Gross Benefit of $4.8 million. This is approximately 1.4% of PGE's NVPC forecast.[3] Also included in PGE's initial NVPC forecast is an additional net savings of approximately $4.5 million related to the full self-integration of

[2] Of those eight months, effectively five of the months (i.e., January through May) include a time period when PGE was self-integrating its wind resources. PGE began self-integration on December 14, 2017.
[3] Using PGE's March 30, 2018 NVPC forecast, less PTC benefits.

PGE's wind resources.[4] Support of full self-integration of PGE's wind resources is an indirect benefit of PGE's Western EIM participation.

Q. How did PGE estimate the direct Western EIM benefits in its 2019 forecast?

A. In order to estimate 2019 benefits that directly result from PGE's participation in the Western EIM, PGE engaged E3 to conduct a benefits study. As described in PGE Exhibit 300, the E3 study estimated the benefits from sub-hourly dispatch savings.

In its study, E3 identifies sub-hourly dispatch savings as having two components: (1) base dispatch cost savings and (2) additional dispatch cost savings associated with PGE maintaining lower reserve requirements. In its testimony, PGE collectively refers to these savings as sub-hourly dispatch savings.

Q. Why did PGE conduct a study to forecast 2019 benefits?

A. There are two reasons. First, PGE conducted a study to forecast 2019 benefits because parties stipulated to this requirement in OPUC Docket No. UE 319. Therein, parties agreed that PGE would "engage an independent third party to complete a Western EIM cost-benefit study to be used in its 2019 Annual Update Tariff (AUT) filing."

Second, where feasible, PGE prefers to forecast NVPC under normal conditions (i.e., average load, hydro, etc.). This is consistent with the basic principle of MONET, which is to produce a final test year NVPC forecast that reflects a baseline (or deterministic) forecast of all variables, including sales from (and purchases for) PGE's resource portfolio under normal conditions (e.g., normal plant operations, water, wind flows, and weather). The results produced by E3 for PGE's NVPC forecast are consistent with PGE's preferred

[4] BPA Variable Energy Resource Balancing Services 30/15 savings less full self-integration costs for 2019.

approach, because the results are derived from inputs that were assumptions under normal conditions.

Q. Do you agree with Staff's characterization of the E3 benefit study?

A. No. In contending that the E3 benefit study result is too low, Staff compares its estimate (i.e., $6.8 million) to an E3 study result of $3 million. However, Staff omits the additional dispatch cost savings associated with PGE maintaining lower reserve requirements. The correction of this omission results in a comparable E3 study result of $4.8 million (i.e., the gross benefit proposed in PGE's NVPC forecast). That is, the correct comparison would be Staff's projection of $6.8 million to PGE's proposed $4.8 million.

Q. In its testimony, Staff suggests that variable maintenance costs should be removed from benefit measurements if it is used as the basis for a NVPC forecast. Can you anticipate the impact to PGE's EIM benefit forecast if incremental variable maintenance costs/savings were removed?

A. Yes. We would anticipate the EIM benefit to be lower. As Staff correctly identifies, PGE was a net importer during the fourth quarter of 2017 and first quarter of 2018 (footnote 3, page 8 of Staff Exhibit 100). This means that PGE was reducing generation (i.e., importing energy) more often than it was increasing generation (i.e., exporting energy) in the EIM market. As such, if variable maintenance costs are removed from the benefit measurement, PGE's actual benefits to-date would be reduced overall. This is because PGE's avoided variable maintenance cost benefits due to decreased generation are greater than the incremental variable maintenance costs that have been incurred. Furthermore, we would anticipate this trend in actuals to continue for 2019, because the EIM benefit studies produced by E3 for PGE have demonstrated that PGE is projected to be a net importer in the EIM.

Q. Please summarize PGE's response to Staff's proposed adjustment.

A. PGE proposes no change to the Western EIM benefits proposed in the 2019 test year. PGE appropriately forecasts the direct Western EIM benefits using a method to which all parties stipulated in OPUC Docket No. UE 319. The forecast is also a reasonable result for a forecast under expected normal conditions when appropriately compared to Staff's estimate.

B. California-Oregon Border (COB) Trading Margins

Q. Please summarize Staff's proposal regarding COB trading margins.

A. Staff argues that PGE's COB trading margin forecast method understates the margins, because while PGE accounts for hourly variation in price, it does not account for daily variation in price. Staff also argues that PGE underestimates the number of transactions because "in hours where [PGE's] method allows sales at COB it ignores the historic values of purchases, and in hours where it allows purchases at COB it ignores the historic values of sales." In order to capture this intra-day variability, Staff proposes a methodology, using non-relevant and inconsistent data to calculate a "COB transaction value per dollar of margin." Staff's method results in unreasonable and inflated hypothetical COB gains based on calculated MWh volumes that are physically impossible, given our AC southbound and northbound transmission rights.

Q. Did Staff raise this issue in previous proceedings?

A. Yes. In UE 319, Staff argued that PGE's method for forecasting a COB trading margin was understated because PGE did not account for intra-month variability of prices in its forecasting method.

Q. Has PGE addressed Staff's concerns regarding intra-month variability in its initial filing in this proceeding?

A. Yes. PGE has included in MONET the results of a new method using actual hourly data and market forward curves to produce a more granular forecasted result. PGE's method, unlike Staff's proposal, produces a result that is consistent with PGE's actual ability to use its firm transmission access to sell or purchase power at the COB market.

Q. Do you agree with Staff's proposal in this proceeding?

A. No. Unlike PGE's methodology described in PGE Exhibit 300, Staff's results use methods and calculations that are inconsistent and devoid of a logical basis. The end results are grossly overstated, difficult to replicate, and highly volatile when they are stress tested, in addition to being simply unobtainable under real world conditions.

Q. What are Staff's main arguments for changing PGE's forecasting method?

A. Staff's main arguments are:

1. PGE's method does not capture daily variation in prices; and
2. PGE's method underestimates the number of transactions at COB because it ignores the historic value of purchases and sales at COB.

Q. Do you agree with Staff's arguments?

A. No. First, PGE's method <u>does</u> account for daily variation in prices. As described in PGE Exhibit 300, PGE's method creates a weighted price shape for COB by hour and day of the week (i.e., weekday, Saturday, or Sunday). By arguing that PGE's method does not account for daily variation in prices it appears that Staff is actually arguing that PGE should be able to reasonably forecast unique pricing for different weekdays on a forward basis and that those weekdays will have significantly disparate energy consumption patterns. Second, Staff's assertion that PGE underestimates the number of transactions because we ignore historical transactions is incorrect. PGE's method uses historical volumes traded at COB.

Q. How does Staff calculate its proposed adjustment?

A. Although difficult to follow in their work papers,[5] Staff appears to take the following steps in calculating their COB adjustment:

1. Staff begins with COB transaction data from January 2014 through December 2015 inclusive of both day-ahead and real-time transactions and computes the margin on all trades using PowerDex Mid-C settled hourly prices that are only indicative of the hour-ahead (i.e., real-time) market.
2. Staff then takes the value of all calculated hourly margins and sums them by month.
3. Staff takes two historic price series of Mid-C and COB prices whose origin and means of calculations are unknown and derives a monthly spread between the hubs.
4. Staff takes the monthly sum of the hourly margins ($/MWh) calculated in Step 2 and divides by the absolute value of average monthly spread ($) calculated in Step 3.
5. The result in Step 3 is what Staff calls "COB transaction value per dollar of margin." However, in actuality, this result is simply a calculated MWh quantity.
6. Staff multiplies the energy quantity derived in Step 5 by an inaccurately derived monthly spread between forward COB and Mid-C curves from February 2018 to obtain an overstated hypothetical COB trading benefit that is approximately four times higher than what PGE included in the February 15, 2018 filing.

[5] PGE has sent several Data Requests to Staff asking for clarifications regarding work papers supporting their COB trading benefit adjustment.

Q. Did PGE review Staff's work papers? What was the result of PGE's review?

A. Yes, PGE has reviewed Staff's work papers and discovered multiple inconsistencies and errors in most of Staff's steps to calculate their adjustment to the COB trading benefit. Additionally, the MWh quantity Staff calculated in Step 5 is physically impossible to attain for a number of months because it exceeds PGE's transmission rights.[6]

Q. What are PGE's specific issues with Staff's proposal?

A. PGE has found many issues with Staff's method, including the data, calculations, and assumptions. Some of these issues are categorized based on the steps identified above:

1. Step 1: The PowerDex Mid-C prices used by Staff are only indicative of the hour-ahead market. Thus, Staff is mixing day-ahead prices with real-time prices, ignoring the day-ahead market cost basis for the bulk of the COB transactions. This lack of data consistency results in an inaccurate margin between COB and Mid-C.
2. Step 1: Staff includes trade data for locations other than COB, inflating the number of transactions.
3. Step 3: Despite obtaining both positive and negative results, Staff assumes that the spread between COB and Mid-C hubs is always positive. Additionally, although stating that the COB and the Mid-C data they used was collected from ICE in 2017, Staff was not able to provide the underlying formulae or a source document.[7]
4. Step 4: Staff divides the summed data by averaged data for same periods of time, which is incorrect algebra, and it yields inaccurate and unreliable results. Staff's

[6] For example, the derived amount of energy for February 2014 is over two million MW, or 3,142 MWa for the month. This amounts to more than the entire average load for February and eclipses the 296 North to South and 600 South to North of absolute maximum transmission capacity available.
[7] See Staff's response to PGE Data Request No. 007 provided as PGE Exhibit 1401.

calculations serve to introduce significant bias into the data, resulting in exorbitant MWh quantities that PGE could not actually deliver in the real world.

5. Step 5: As stated above, the MWh quantity Staff produces is unobtainable given PGE's AC intertie transmission rights.
6. Step 6: Staff miscalculates the monthly spread between COB and Mid-C by reversing the Mid-C off- and on-peak price weights.

Q. Notwithstanding the errors in Staff's methodology and the fundamental flaws described above, would this method produce consistent COB trading margin values?

A. No. Staff's methodology is extremely volatile, resulting in large variations in benefits depending on which market forward curve is used. To calculate the $22.0 million COB trading margin benefit, Staff used COB transaction data from January 2014 to December 2015 with the February 15, 2018 price curve. If updated with the March 30, 2018 NVPC update curve, this benefit would significantly decline to approximately $4.0 million. Updating Staff's method with the market forward curve to be used in PGE's July 6, 2018 NVPC update decreases Staff's calculated benefit to $0.4 million in total.[8] In other words, simply replacing the February 15, 2018 market forward curves used in Staff's analysis with updated market forward curve data reduces Staff's gross benefit by over $21 million, removing, effectively, their entire adjustment.

Q. Please summarize PGE's response to Staff's proposed adjustment.

A. PGE stands by its method for forecasting COB trading margins. PGE's method relies on actual trading activity, forward trading curves, and a consistent methodology that has previously been used in PGE's power cost forecasting. Staff's method is based on faulty

[8] See PGE's confidential work papers in support of PGE Exhibit 1400 for this analysis.

calculations that are unsupported, inconsistent, and erroneous, producing results that are exorbitant, highly volatile, and unobtainable under real world conditions.

C. Wind Resource Capacity Factor

Q. Do you agree with Staff's and AWEC's proposed adjustments to PGE's wind resource capacity factors?

A. No. Staff and AWEC point to regulatory processes that, in some instances, occurred over ten years ago to form the basis of their proposed adjustments. Staff appears to re-characterizes the record, which results in broad, misleading, and factually incorrect conclusions. Neither Staff nor AWEC propose any methods that lead to a more accurate NVPC forecast or improved ratemaking. Rather, they propose punitive adjustments bordering on retroactive ratemaking.

Q. What is the basis of Staff's and AWEC's adjustment?

A. Staff claims that PGE was aware of and advised on the risks associated with forecasted capacity factors when PGE decided to construct its wind facilities and that PGE chose not to mitigate, these risks when building the facilities. As such, Staff concludes that it is appropriate to partially impute a permanent dollar amount in NVPC based on the originally forecast capacity factors for these facilities. Staff further rationalizes their approach by stating that their method will help to incent PGE to produce a more accurate capacity factor forecast in future competitive bidding processes.

AWEC bases their adjustment on a similar construct. AWEC argues that using the current five-year average is unfair because PGE sees all the benefits of equity returns, while customers bear all the risks of investments failing to materialize at a level originally forecast.

Q. Staff and AWEC suggest that PGE customers have borne all the risks (and associated costs) of lower than forecast capacity factors. Are they correct?

A. No. When PGE's wind assets under-produce relative to forecasts, PGE incurs the cost of higher priced replacement energy <u>and</u> the cost related to the under-production of federal Production Tax Credits (PTCs). Since 2008, the lost energy of actual wind generation relative to forecast has cost PGE (and its shareholders) an estimated $41.7 million, while the lost value of PTCs in actual results relative to the benefit provided to customers has cost PGE approximately $37.2 million.[9]

Q. Is Staff accurately characterizing what PGE knew at the time Biglow was constructed?

A. No. In determining the initial capacity factors for our wind plants, PGE relied on the expertise of independent industry experts to prepare these forecasts. The study results PGE received and relied upon for Biglow specifically state that uncertainties around wind speed, flow, and other wind qualities <u>were considered</u> in their analysis.[10] In fact, contrary to Staff's suggestion,[11] there is <u>no</u> recommendation within the original 2005 wind study that PGE mitigate the risks associated with the actual wind at the site.

Q. Staff seems to be inferring that PGE was somehow imprudent in evaluating Biglow. Please provide some history of how Biglow 1 came to be constructed and included into customer prices.

A. The construction and completion of Biglow 1 was the result of a winning bid within PGE's 2003 Request for Proposals in response to PGE's 2002 Integrated Resource Plan (IRP) Final Action Plan acknowledged through Commission Order No. 04-375. An independent

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[9] See PGE's work papers to PGE Exhibit 1400 for this analysis.
[10] See page 15 of the 2005 Garrad Hassan Study, as provided via confidential Staff Exhibit 303.
[11] See Staff Exhibit 300, page 13, lines 13-14.

evaluator monitored and evaluated all aspects of PGE's RFP process and determined that the process met industry standards. Biglow was ultimately included into customer prices through Docket No. UE 188.

Q. Were parties able to review the 2005 Wind Assessment in UE 188, which ultimately formed the basis of PGE's capacity factor forecast for Biglow 1, 2, and 3?

A. Yes. PGE's wind capacity factors were fully examined in UE 188 and through every rate case and annual NVPC filing since then. Staff states that PGE chose not to convey the risk factors indicated in the 2005 Garrad Hassan (GH) study to stakeholders.[12] This is incorrect. PGE originally provided the 2005 GH study as part of PGE's confidential work papers to PGE Exhibit 200 in UE 188, giving all parties who had signed the protective order access to the same information. Furthermore, PGE responded to a number of OPUC data requests, in UE 188,[13] in which annual capacity factors were highlighted and the 2005 GH study along with a variety of information related to PGE's third party assessment of wind were included.

Q. Please describe the maturity of wind forecasting methods and technology in 2005.

A. During the time of PGE's construction and completion of Biglow, wind forecasting was still a relatively new subject area in the United States, with limited expertise or history to draw upon. This led to the systematic over forecasting of wind capacity factors, not only for Biglow, but also throughout the country for large-scale wind projects. In fact, a 2014 study by DNV-GL found that wind farms constructed during the period of 2001-2009 produced on average approximately 9% less energy compared to their pre-construction P50 estimates[14] during their first year of operation. Since then and in conjunction with the rapid increase of

[12] Staff Exhibit 300, page 13, lines 11-12.
[13] See PGE's response to OPUC Data Request Nos. 006, 032, and 033 in Docket No. UE 188.
[14] A P50 forecast assumes that given the existing data, that there is a 50% chance that the project's long-term average production will exceed the long-term P50 and a 50% chance that it will not.

wind turbine data and experience across the country, the forecasting of wind capacity factors has and continues to improve.

Q. Staff also argues that PGE could or should have known it was over-forecasting its wind capacity factors. Is this true?

A. No. Staff uses PGE's response to OPUC Data Request No. 566 from Docket No. UE 319, where we indicate that we began to become aware of consistent monthly underperformance at Biglow between 2009 and 2010 as support for their assertion that we should have reduced the long-term average forecasted capacity factor for Biglow 3. By the beginning of 2010, the point at which PGE would have requested to include Biglow 3 into customer prices, through Docket No. UE 215, we would have only received two full years of wind generation data for Biglow 1 (i.e., 2008 and 2009). While these data did show underproduction relative to PGE's forecast, it was a limited data set from which to make broad conclusions that would have affected PGE's overall wind generation forecast, and would have likely resulted in considerable push back from other parties.

Staff also points to the change in layout and total installed generation compared with the GH study as reason for PGE to reduce its assumed capacity factor. However, PGE did not know what the potential effects of these changes would be at the time, which is what helped lead to the commissioning of a new study that GH produced in 2012, after Biglow 2 and 3 were already in service. Ultimately, PGE did not have evidence of a consistent trend until after all three Biglow phases were included in rates and, even now, there is very limited data to evaluate the true long-term annual average forecast.

Q. When did PGE change from the wind capacity factors originally forecast for Biglow 1, 2, and 3 to the current five-year average method?

A. PGE proposed the change to the more accurate method in Docket No. UE 262, PGE's 2014 GRC.[15] In support of this change, PGE stated the following:

> A forecast based on actuals is fair, transparent, reflects changing operational experiences, incorporates the effects of recent environmental conditions, is not tied solely to outdated forecasting techniques, and is consistent with other aspects of PGE's power cost forecast where actuals serve as the basis for the forecasted value (e.g., thermal forced outage rates, generation under certain wind PPAs (Klondike II), and the BPA imbalance premium).

Q. What was Staff's response to PGE's methodology change?

A. In UE 266 Staff Exhibit 100, Staff summarizes a number of PGE's proposed changes and updates to 2014 NVPC, including "the use of a five-year rolling average when forecasting wind energy,"[16] followed by the statement that "Staff considers the above changes and updates reasonable."[17]

Q. Did any other party appear to take issue with PGE's modelling change to a five-year average for wind energy?

A. No. No other party, including AWEC's predecessor the Industrial Customers' of Northwest Utilities (ICNU), provided testimony regarding this modeling change, and prices for PGE's 2014 NVPC that included this approach were subsequently approved through Commission Order No. 13-280.

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[15] After the initial filing of Docket No. UE 262, the NVPC portion of the case was subsequently bifurcated and docketed as Docket No. UE 266.
[16] Docket No. UE 266, Staff Exhibit 100, page 3, line 8.
[17] Ibid, page 4, line 1.

Q. Do Staff's or AWEC's proposals result in a better forecast of PGE's wind resources?

A. No. Staff's and AWEC's adjustments are strictly punitive in nature. They create forecasts of wind energy that are not directly tied to the operational characteristics of the plants either from a historical actuals standpoint or from a forecasted energy standpoint.

Q. Does PGE need an additional incentive to ensure accurate wind capacity factors are forecast in a competitive bidding environment as Staff and AWEC suggest?

A. No. Not only is this argument misplaced within a general rate case setting, where no wind generating assets are being requested for inclusion into PGE customer prices, PGE is already incentivized to accurately forecast wind capacity factors. As mentioned above, when PGE's wind resources under-generate relative to forecasts, PGE must make up the difference with more costly power, and is at greater risk of under collecting PTCs both on an annual basis and over the life of the project. Per IRS rules, qualified renewable energy resources generate PTCs, which are used as a tax offset, for the first ten years of operations. Therefore, under-generation, relative to original forecasts leads to higher costs for PGE. With the original capacity factor contributing to the first five years of PGE's forecasted wind production, PGE must absorb any differences between forecast and actual PTC production.

Q. Please describe the current process for reviewing wind capacity factors through the competitive bidding process.

A. As part of Commission Order No. 13-204 for Docket No. UM 1182, the OPUC stated that: "(to) ensure that wind capacity factors are being examined on an equal basis during bid evaluation, we adopt the utilities' proposal to use a qualified and independent third-party technical expert to review the expected wind capacity factor associated with each project on the short list, including benchmark resources. We conclude that this will best achieve the goal of ensuring that all resources are compared fairly in the RFP process."[18] The competitive bidding guidelines were subsequently updated to reflect this change through Commission Order No. 14-149, where Guideline 10(f) now states that: "Utilities are to use qualified and independent third-party experts to review the expected wind capacity factor for all projects on the shortlist."[19]

Q. Has PGE used a qualified and independent third-party expert to review expected wind capacity factors within any of its Requests for Proposals (RFP)?

A. Yes. As part of PGE's 2012 Renewable Resource RFP in which the Tucannon River Windfarm was ultimately selected, PGE retained a qualified independent industry expert to review the wind assessments of all short listed wind offers and to provide recommended capacity factor adjustments, resulting in a 1-2% decrease for most offers. The IE reviewed the study and methodology used and concluded it was conducted fairly and was unbiased, resulting in reasonable adjustments to bid capacity factors.

Q. What other misconceptions are put forth in Staff's and AWEC's testimony on wind capacity factors?

A. Staff asserts that PGE bears none of the PTC risk associated with forecast error. This is incorrect. It appears that Staff bases this assertion on the premise that PGE can now update its PTC forecast annually in NVPC and that this is compared to PGE's actual results via the PCAM. What Staff doesn't state is that due to the deadbands and sharing mechanisms within the PCAM that treat PGE's PTCs in a fashion similar to all other NVPC, differences

[18] Commission Order No. 13-204, pages 10-11.
[19] Commission Order No. 14-149, Appendix A, page 4.

between forecasted and actual PTC production are likely to be absorbed within the deadband range.

Staff also states, by way of reference to Oregon Senate Bill 1547, Section 18b that "the Oregon legislature adopted language indicating that the PTC forecast risk is to be borne by customers"[20] Below is the full passage from Oregon Senate Bill 1547, Section 18b:

> Each public utility that makes sales of electricity shall forecast on an annual basis the projected state and federal production tax credits received by the public utility due to variable renewable electricity production, and the Public Utility Commission shall allow those forecasts to be included in rates through any variable power cost forecasting process established by the commission.

PGE is unclear as to how Staff interprets this to mean customers bear the risk of PTC forecasts.

Q. Please summarize PGE's position with respect to Staff's wind adjustment and basis.

A. Both AWEC and Staff propose methods of forecasting wind energy production that will undoubtedly lead to a forecast that is not representative of normal conditions. PGE's current, approved forecasting method of using a rolling five years of generation provides for a more accurate and normalized forecast of wind energy production. Variable resources will undoubtedly generate at quantities that differ from NVPC forecasts, and should the resources generate at levels below forecast, PGE is responsible to replace those deliveries with power from its dispatchable generating resources or from power purchases in the wholesale market, or both. The cost of this replacement power and the cost of lost PTC benefits both intra-year and over the life of PTC generation are borne by PGE shareholders unless the costs are high enough to trigger the PCAM's provisions. Therefore, every

[20] Staff Exhibit 200, page 19, lines 12 and 13.

incentive exists (and appropriate processes are in place) for PGE to ensure that capacity factors are accurately calculated within the RFP process.

D. Forward Curve and Hedging Costs

Q. Please describe AWEC's proposed adjustment related to the forward curve and hedging used in MONET.

A. AWEC argues that utilities have a tendency to overstate forward market prices relative to actual market prices. To support their position, AWEC performed an analysis comparing historical market forward prices to average monthly settled spot prices recorded from 2006 through 2017. AWEC assumes any differences between forward and settled actual prices are due to "forecast errors." They then compute the percentage difference between the market forward prices and the final settled spot prices. AWEC reduces the forward prices used in the March 30, 2018 NVPC update filing using their calculated "forecast error" percentage difference. Finally, AWEC calls PGE's hedging practices into question and proposes that only 80% of the costs and benefits of PGE's hedging gains and losses be included in customer prices. The sharing recommendation is based largely on AWEC's claim that the market prices are biased and are in effect embedding a risk premium into forward prices.

Q. Do you agree with AWEC's analysis and conclusions?

A. No. AWEC's fundamental premise is incorrect. The market forward price curve is <u>not</u> a "forecast" as AWEC suggests. Rather, it represents the market's view of the cost to execute a transaction today (the curve date) for delivery in the future. In the AUT price setting process, any open position at the final curve date is priced at the forward curve. PGE then has the option (and bears the risk) of going out and filling its remaining open position at the market curve price (or as close to the market curve price as possible), or holding the position open to see if prices decline for reasons such as good hydro conditions, excess market supply, mild summer weather (shareholder risk). PGE also bears the post-AUT curve date risk of price spikes due to items such as supply constraints (notably variable energy resources), wild fires and weather excursions (extreme temperatures). The PCAM was developed to share the risk (asymmetrically) between customers and shareholders on the final, executed cost variance between the AUT Cost Forecast and final incurred costs for the year.

Q. What issues are there with AWEC's analysis?

A. AWEC's analysis contains a number data issues, including the use of an incorrect basis for their calculation of percentage error, use of the incorrect forward curve for most years, and, most notably, comparing forward prices to actual spot market prices.

Q. What is the problem with comparing forward prices to actual spot prices?

A. They represent two different things. The forward price represents the price <u>today</u>, for a product that will be delivered (or settled) in the future. The spot price is the price for the product on or during the day or month of delivery and is more volatile as it is subject to market conditions on that specific day/month. In using spot prices, AWEC's methodology implicitly assumes that PGE should wait until the actual day of a forecast period to make any purchases (or sales) of gas and electricity needed to serve load. In reality, relying only on the spot market without an effective hedging strategy would put reliability at risk and would likely affect market prices, resulting in higher costs and greater volatility, possibly as large as that in the California market during the 2000-2001 period. For these reasons, PGE purchases both gas and power in the forward market. Doing so results in greater price stability (i.e., reduced volatility) for customers and provides greater assurances that PGE will be able to prudently meet its "must serve" obligations. PGE does utilize the spot market to purchase or sell fuel or power to balance out changes in load and PGE generation that occur after the final AUT forecast. NVPC variances resulting from differences between the AUT curve and spot prices are properly reflected in the PCAM and shared (asymmetrically) between customers and shareholders.

Q. AWEC briefly mentions structural changes in natural gas and power markets. What market trends has PGE seen in gas and power markets?

A. According to available data,[21] average day-ahead and monthly settled market power and gas prices peaked towards the end of 2005, trended lower for a couple of years, rose again in 2008, before rapidly decreasing in 2009. These prices then increased slightly in 2013 and 2014, before again moving back down.

Q. How does this experience compare to the market forward curve?

A. During the periods of increasing actual settled prices for gas and electric, the market forward curve on average exhibits prices <u>below</u> month-ahead prices for gas and day-ahead prices for electric. Specifically, during 2003-2005, a period of increasing prices (and a period that AWEC did not include in their analysis), the market forward curve on average is well below settled prices for each year in every market used in the NVPC forecast. Similarly, in 2008, 2013, and 2014, years where settled prices exhibit an upward trend over the previous year, the market forward curve on average is again below the settled market prices in each of these years for most gas and electric markets used in setting forecasted NVPC.[22]

[21] As provided in confidential work papers supporting PGE Exhibit 1400.
[22] See PGE's confidential work papers supporting PGE Exhibit 1400 for this analysis.

Q. So, whether the market forward curve trends higher or lower than settled prices is affected by the directionality of actual prices?

A. Yes. Generally, when actual prices trend higher year over year, market curves tend to be lower than actual prices, while in an environment of consistent declines in actual prices the market forward curve can be higher on average.

Q. Will actual prices in 2019 be lower or higher than current prices?

A. We don't know. As we noted above, the market price trend has not been consistent over the last few years. To imply that we should adjust the forward curve in the AUT would imply that we know the trend of market prices.

Q. Please describe PGE's process for developing the market forward curve.

A. PGE's power desk generally begins developing a market forward curve approximately two years out from a prompt year (i.e., The date for delivery of a commodity). At this point in time, energy trading in the Northwest energy market is relatively illiquid beyond calendar year quotes. In order to arrive at a monthly indicative price, PGE utilizes Intercontinental Exchange[23] (ICE) trading platform data along with actual broker (i.e., market) quotes. Additionally, to further support monthly indicative prices, PGE utilizes spreads between Mid-Columbia and California energy trading hubs[24] as the California market exhibits better liquidity this far into the future.[25] These calendar "strips" are then shaped to introduce the seasonality expressed by the market historically. At approximately one year out from a prompt year, the spread for quarterly strips of energy become liquid and PGE utilizes this

[23] ICE offers a suite of over 1000 energy futures and options contracts. Refer to: https://www.theice.com/energy for additional information.
[24] A spread is the price delta between trading hubs.
[25] For example, if there is a buyer of California hub energy for $45.00, and a seller of the spread between the California hub and Northwest hub for $12.00 on the same day, then the value of the energy at the Northwest hub for that day is at least $33.00.

information, coupled with historical weights for each month of the prompt year, to develop a monthly forward price. At approximately six months out from the prompt year, the Northwest market will begin trading monthly power and gas contracts. At this point, using the monthly broker quotes, coupled with current quarterly and yearly information from ICE and other sources, PGE's power desk can directly produce monthly pricing. This process continues through to PGE's final curve update on November 15th, when a five-day average of recent monthly forward prices are averaged in order to further smooth out any day-to-day volatility in the market. By the November curve date, monthly prices are readily observed in the forward curve for that prompt year.

Q. Is the market forward curve validated?

A. Yes. While the power desk is responsible for recording the market view of the forward curve, PGE's Risk Management department is responsible for validating market forward curves. Risk Management also enforces the internal PGE limits on the Power Supply Operations group (Power Operations). In order to provide Risk Management with the necessary independence to objectively evaluate the activities of Power Operations, there is a functional separation in reporting structure, with Risk Management reporting directly to the Chief Financial Officer (CFO) and the Risk Management Committee (RMC), not Power Operations.

Q. Please summarize the process Risk Management uses to validate market forward curves.

A. On a monthly and quarterly basis and for each forward curve used in PGE's NVPC forecasts filed with the Commission, Risk Management compares the forward market curves observed by Power Operations to third party sources (including broker quotes and price indices) to ensure the prices observed and documented by Power Operations accurately reflect the current market prices. PGE has a policy that the curves observed by Power Operations must be within 5% of third-party quotes. In the event any price variances exceed the 5% threshold, Risk Management will adjust the observed curve to bring it to within 5% of the third party sources.

Q. What other controls are in place?

A. After PGE performs the initial validation, a separate Risk Management Analyst reviews the validation to ensure that: all prices were validated, variances greater than 5% were resolved, calculations were accurate, and validated curves were loaded into PGE's risk management system. This process is also control tested by PGE Internal Audit as part of the Sarbanes-Oxley Act (SOX) testing program. Externally, PGE's external auditor (Deloitte) also performs substantive SOX[26] audit procedures on Risk Management's controls and valuations.

Q. Have parties raised issues with the market forward curve in previous cases?

A. Yes. Most recently, Staff discussed PGE's forward price curve in UE 283 (PGE's 2015 general rate case).

Q. What was determined in UE 283?

A. PGE and parties agreed that no changes would be made to the market forward curve. In addition, the Commission required PGE to hold a workshop addressing the development of the market forward curve. PGE held the required workshop on March 4, 2015.

[26] This includes benchmarking PGE's internally-developed price curves to curves developed and validated by Deloitte's industry specialists to verify prices and valuations are within tolerances.

Q. Is PGE aware of any resulting recommendations from parties that PGE should modify either its forward curve or hedging practices subsequent to the workshop?

A. No.

Q. Has PGE modified or changed any practices around the development of forward curves since that time?

A. No.

Q. You mention comparing the market forward curve against a trading curve such as ICE. Could PGE use the ICE curve in place of the forward curve developed in-house?

A. No. While the ICE market curves provide guidance in both the development and validation of the market forward curve, PGE's market forward curves are more granular. As we discussed above, when you look farther out in time, the ICE curve only includes quarterly or annual price quotes or strips. As such, the ICE curve simply cannot be used to replace monthly forward prices at the level of granularity PGE requires for forecasting economic dispatch of its plants. While the ICE curves have become more robust over time, the Mid-C curve - of particular interest here - can display shaping across a quarter that is biased by purely financial trading activity or by a lack of trading. It is essential to have the monthly prices marked as accurately as possible, particularly over shoulder months when our thermal plants begin to move "in and out of the money" relative to the forward heat rates. PGE traders use as much market information as possible to arrive at an accurate mark.

Q. Has AWEC proposed using a different curve or made the argument of there being a more accurate curve than what PGE uses?

A. No. AWEC simply imputes a discount onto the market forward curve values. This discounted price does not result in a more accurate curve, nor does it lead to setting a more accurate forecast of NVPC. The discounted forward curve simply reduces PGE's forecasted NVPC below the expected actual costs PGE will incur, ensuring that PGE will under-recover its prudently incurred NVPC. Additionally, this proposal is inconsistent with any validation or auditing process that PGE and its third-party reviewers conduct and is at odds with decades of consistent treatment of forward prices used in the development of forecasted NVPC.

Q. Are there other issues with adopting AWEC's curve adjustment proposal?

A. Yes. In addition to the issues discussed above, PGE would need to maintain and update market forward curves based on AWEC's proposed methodology in conjunction with our market forward curves. Maintaining two divergent market forward curves would produce conflicting information that would materially affect PGE's ability to execute transactions, to accurately plan and position our generation portfolio to minimize NVPC, and to make business decisions that directly affect customers. There would also be secondary effects to items such as long-term opt out transition charges,[27] COB trading margins, economic dispatch of thermal plants, and potential accounting implications for deferral of gains or losses under ASC 980 to name a few. Additionally, it is unclear to PGE how this method would be updated going forward.

Q. In summary, why are market forward curves appropriate to use for forecasting NVPC?

A. As we stated above, PGE develops the market forward curves based on current trading activity for the test year and compares it against third party sources on a regular basis. The market forward curves represent PGE's best indication of future market prices for a given

[27] PGE's initial conclusion is that AWEC's proposal would likely increase opt out charges.

time period based on actual information available at the time of the market forward curve "snapshot." PGE uses its forward curve to dispatch thermal plants on a forward basis and revalue the trading portfolio every day. In order to successfully manage the company's position every incentive exists to produce the best possible forward curve. PGE executes transactions and plans based on the same market forward curves used to forecast NVPC. PGE's market forward curves are also used for financial and SEC reporting purposes. Additionally, there is already a mechanism in place to protect customers from variances between the AUT cost forecast and actual incurred costs for the year. Recognizing that a forecast is never perfect, the PCAM returns funds to customers if overall actual power costs decrease by greater than $15 million and collects additional funds if overall power costs increase by greater than $30 million.

Q. AWEC also suggests that PGE's hedging strategy is imprudent and that the full costs of PGE's hedging should not be borne by customers. Has the Commission reviewed PGE's hedging practices before?

A. Yes. PGE's current hedging strategy and practices have been reviewed by the Commission on multiple occasions, most recently in the 2012 AUT (Docket No. UE 228). In UE 228, CUB and ICNU disputed PGE's hedging practices.

Q. What was the resolution of this issue in UE 228?

A. The Commission concluded specifically that: "PGE's overall hedging strategy to be prudently designed."[28] The Commission continued by stating:

"(s)pecifically, we find that the MTS [mid-term strategy] is a reasonable approach to addressing the three-year period between the company's short-term hedges and purchases

[28] Commission Order No. 11-432, page 8.

and the company's long-term resource investment, and agree that the appropriate goal is to address PGE's entire NOP [net open position]."[29]

Q. Has PGE made changes to its hedging strategy since Commission Order No. 11-432?

A. No. PGE continues to follow the same strategy, which was presented during a Commission workshop following Commission Order No. 11-432 and is included here as PGE Exhibit 1402C. Additionally, a summary of PGE's Mid-term Strategy program is provided as PGE Exhibit 1403C.

Q. AWEC suggests that circumstances have changed since the Commission last reviewed PGE's hedging practices in UE 228. Specifically they argue that PGE now relies very little on wholesale markets to meet resource adequacy requirements. Is this correct?

A. No. AWEC's primary argument is that PGE no longer has a need to hedge because of our recent resource acquisitions. While the completion of Carty, Port Westward 2, and Tucannon have reduced PGE's resource deficit, the primary commodity that PGE hedges is not power but gas. PGE now has five separate generating resources that run on natural gas for a combined nameplate capacity of over 1,800 megawatts.[30] As such, PGE (and customers) have a large exposure to changes in gas prices and supply.

Q. Was PGE hedging gas during UE 228?

A. Yes. In fact, PGE specifically indicates in UE 228 that our preference is to enter into gas hedges first as they offer a more efficient hedge due to our high efficiency gas-fired resources.[31]

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[29] Ibid.
[30] These resources are Beaver, Coyote Springs, Port Westward 1, Port Westward 2, and Carty.
[31] UE 228, PGE Exhibit 400, page 13.

Q. What about AWEC's argument that PGE has an incentive to continue following its mid-term strategy.

A. The fact is, PGE did not develop, nor does it continue to follow its mid-term strategy (MTS) to reduce shareholder risk as AWEC suggests. As we indicated in UE 228, the MTS evolved out of customers' desire for improved rate predictability. PGE does not hedge to receive a dollar benefit for shareholders. PGE hedges to provide price stability to customers (in the near term, approximately 24 months, we also procure gas/energy to reduce supply risk). Thus, the notion of sharing hedging costs and benefits, as AWEC suggests, is not a logical concept. AWEC argues that PGE hedges up to 100% of its open position[32] and this reduces shareholder exposure.[33] This is misleading. Since the OPUC approved AUT forecasting methodology prices PGE's open position at the forward curve, there is in effect a *defacto* 100% hedging of the open position within MONET (from the customer perspective) with the final AUT update on November 15. So whether PGE layers in hedges over time, or the OPUC effectively prices one big hedge for customers on the final AUT curve date – the positon is 100% hedged for customers going into the test year in question. Furthermore, as referenced above from Commission Order No. 11-432, the Commission has agreed that the appropriate goal is to address PGE's <u>entire</u> net open position. Once the open position receives the final November curve pricing, PGE shareholders bear the risk, within the confines of the PCAM mechanism, of PGE Power Operations not being able to close the open position at the forward market price.

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[32] AWEC Exhibit 100, page 17, lines 16-17.
[33] AWEC Exhibit 100, page 18, lines 10-11.

Q. In summary, why is AWEC's proposed adjustment to the treatment of hedging in forecasted NVPC inappropriate?

A. PGE's hedging strategy executed as part of the MTS was prudently developed, implemented, and has been previously reviewed and declared reasonable by the Commission. The fundamental reason behind the strategy (i.e., to reduce customer's exposure to market volatility), the methods employed for achieving this (i.e., the mid-term strategy), and the need to continue a consistent practice (i.e., continued exposure to price volatility) have not changed since the Commission issued Order No. 11-432.

E. Production Tax Credits

Q. Please describe AWEC's proposed adjustments related to the production tax credit (PTC).

A. AWEC proposes two separate adjustments with respect to PGE's forecasted PTCs. First AWEC argues that PGE should increase its assumed price from 2.4 ¢/kWh up to 2.5 ¢/kWh for 2019. AWEC supports their argument by performing an analysis concluding that by using the currently forecasted Gross Domestic Product (GDP) implicit price deflator (GDPIPD) for 2019, the PTC rate would increase. Second, AWEC argues that customers did not begin receiving the benefit of Biglow Phase 2 PTCs until August 20, 2009 and therefore, PGE should not begin phasing out the benefit to customers until August 20, 2019.

Q. How do you respond to AWEC's argument for increasing the PTC rate?

A. We have concerns about revising our forecast at this point in time. Based on the current GDP forecast, we believe the PTC rate could increase, but we note that it would only require a slight decrease in the rate of escalation of the GDPIPD for the PTC rate to remain at 2.4 ¢/kWh. Due to the IRS rounding, the PTC rate to the nearest 0.1 ¢/kWh, a slight decrease in the rate of escalation of the GDPIPD will produce a PTC rate of less than 2.45 ¢/kWh, which would round to the current 2.4 ¢/kWh, or no change for 2019. In fact, since 2010, actual inflation has been above the rate required for a PTC rate increase only three times.

Q. How does PGE propose to forecast the PTC rate for 2019?.

A. We propose updating the PTC as close as we can to 2019. This update would be our November 6th NVPC update. We propose using the applicable forecasted inflation rate currently available at that time.

Q. What is PGE's response to AWEC's second issue regarding the phase out of Biglow 2 PTCs?

A. AWEC is incorrect regarding when customers began receiving the PTC benefits related to Biglow 2. PGE brought the Biglow 2 project into service in phases and, as such, PGE provided the PTC benefit to customers consistent with the phasing in each turbine or set of turbines. In PGE's 2009 Renewable Adjustment Clause filing (Docket No. UE 209), actual Biglow 2 generation beginning in June of 2009 was used to calculate the PTC credit. PGE used a combination of Biglow 2 actual generation through November 2009 and a partial forecast of December 2009 generation to calculate the 2009 Biglow 2 revenue requirement amount that was deferred and subsequently included in customer prices through PGE's 2009 Schedule 122 tariff filing. These documents are provided in PGE's work papers.

Q. Please summarize PGE's response to AWEC's PTC concerns.

A. In summary, PGE proposes to calculate the PTC rate in its November 6, 2018 filing using published GDPIPD forecast data available at that point in time. Additionally, PGE recommends that no PTC adjustment be made for the timing of the Biglow 2 in service date, as PGE modeled the phasing in of Biglow 2 consistent with the modeling of the phasing out of PTC credits, providing customers the full 10-year forecasted benefit of PTCs.

F. Carty Gas Supply Costs

Q. Please describe Staff's proposed adjustment related to the cost of supplying gas to the Carty Generating Station (Carty).

A. Staff argues that the extra capacity on the 25-mile pipeline (Carty Lateral) from the Gas Transmission Northwest (GTN) mainline to Carty was built by PGE in anticipation of the construction of a second facility at Carty and that the extra-capacity provides no current benefit to customers. Staff is proposing a disallowance of the portion of the Carty lateral expense that exceeds Carty fuel needs.

Q. Do you agree with Staff's proposal?

A. No. In proposing a disallowance of the portion of the Carty lateral that exceeds Carty needs, Staff does not take into consideration the fact that PGE has a different firm transmission service agreement on the Carty lateral than it has on the GTN mainline. In addition, Staff ignores the fact that the design evaluation of the Carty lateral pipeline, at the time of PGE's decision on what size to use, concluded that the 20-inch diameter pipeline was the least cost, least risk option for the single Carty Plant by itself (i.e., one unit/facility).

Q. Please explain the service agreement between PGE and GTN for the Carty lateral.

A. PGE's firm transmission service agreement for the Carty lateral is structured differently than the firm transmission service agreement on the GTN mainline. While PGE pays the GTN tariff rate on the GTN mainline, we pay a negotiated rate on the lateral, which is based on the cost to construct the pipeline. After no other parties elected firm transportation rights on the Carty lateral during GTN's open season, GTN and PGE developed the negotiated rate structure using the estimated costs for GTN to construct, own, and operate the Carty lateral. The GTN tariff for the Carty lateral allows GTN to recover its costs, no more, no less.

Q. Please explain why PGE chose to build a 20-inch pipeline with a gas transportation capacity of 175,000 DTH/day instead of a 16-inch pipeline with a gas transportation capacity of 75,000 DTH/day if current Carty needs do not exceed 75,000 DTH/day?

A. PGE chose to build a 20-inch pipeline because, after analyzing all other options, it was found to be the least cost, least risk option. PGE's proposal for the Carty Lateral pipeline was fully reviewed and vetted by the Commission in PGE's 2016 general rate case (UE 294). As previously mentioned in numerous responses to OPUC Data Requests, PGE selected a 20-inch diameter pipeline based on PGE's analysis to determine the optimal pipeline diameter to ensure gas pressures above the minimum requirements needed for Carty's gas turbine. Contrary to Staff's claim, a 16-inch diameter gas pipeline would have required a compressor station to ensure the necessary pressures for Carty's gas turbine. The required addition of a compression station made the 16-inch more costly than the 20-inch alternative, which did not require a compressor.

Q. Do you agree with Staff's determination that a 16-inch diameter pipeline without a compressor would have been adequate to supply gas to Carty reliably?

A. No. Staff's analysis is incorrect. Staff used gas pressure data recorded at the Carty inlet between July 2016 and April 2018 (approximately 19 months) and added an estimated pressure drop on the Carty lateral to determine the GTN mainline gas pressure. Then Staff averaged the calculated gas pressure on the GTN mainline over the 19 month[34] period to conclude that a 16-inch pipeline without compressor would have been adequate to supply

[34] See Staff Exhibit 300, page 5, lines 13-19 and Footnote 6.

Carty. Staff's method to estimate GTN mainline gas pressures introduces a significant margin of error and is not appropriate to make any conclusion regarding the design of the Carty lateral for two reasons:

1. Using a 19-month average to determine if a 16 inch pipeline can meet Carty's pressure requirements, ignores the fact that the minimum pressure Carty needs must be reliably met in real time at <u>all</u> hours of the day, <u>every</u> day of the year.
2. Using Carty gas pressure data points from 2016 to 2018 is not relevant in determining whether the Carty lateral diameter evaluation was performed properly when the pipeline was designed. The Carty lateral was designed using actual multiple GTN pressure data sets from January 2009 through March 2014; information that was known and measurable <u>at that time</u>.

Q. Does the gas pressure on the GTN mainline vary due to external factors?

A. Yes. Annual and seasonal gas pressure fluctuations on the GTN mainline are dependent on available hydro power, wind power, and gas-fired plant operations. For example, the 2017-2018 mid-Columbia hydro power has been at capacity resulting in reduced power demands from gas generating plants[35] that are fueled through the GTN mainline. Consequently, gas pressures on the GTN mainline were higher. However, in peak conditions when operating at or near capacity, all plants supplied by the GTN mainline require more gas and the combined capacity of the generation plants' gas flow rates can increase to over 300,000 MMSCF/day, resulting in significant decreases of GTN mainline gas pressures. Based on documentation that GTN provided when the Carty lateral was designed, the combined capacity of the generation plants fueled through the GTN mainline

[35] South Hermiston, Coyote Springs, and Calpine generation plants.

can reduce the gas pressure on the GTN to as low as 635 psig.[36] If Carty relied on a 16-inch diameter pipeline without a compressor, the risk of Carty not being able to run would increase significantly, resulting in PGE purchasing expensive energy from the market to replace lost Carty generation, increasing PGE's power costs. This could also create potential resource adequacy and reliability issues. This is not the case for the 20-inch diameter pipeline.

Q. What was the minimum pressure requirement on the GTN mainline for a 16-inch pipeline without compressor?

A. Based on the minimum inlet pressure required for the Mitsubishi 501GAC,[37] PGE determined a minimum GTN mainline pressure requirement of 738 psig. The five years of historical pressure data GTN provided when the Carty lateral was designed showed that approximately 30% of the time the pressure on the GTN mainline would not have met the 738 psig minimum pressure requirement to operate Carty with a 16-inch diameter pipeline without a gas compressor.[38]

Q. What is the result to Carty if minimum pressure requirements cannot be met?

A. Not meeting the minimum gas pressure required for the Mitsubishi 501GAC engine could cause a plant trip, potentially damaging plant equipment.

[36] Pounds per square inch gauge.
[37] The type of engine at Carty.
[38] See Exhibit 1404.

Q. Would PGE pay less if it had elected firm transmission rights for only 75,000 DTH/day instead of 175,000 DTH/day on the Carty lateral 20-inch diameter pipeline?

A. No, PGE pays the same dollar amount regardless of firm rights because the negotiated rate is derived from the costs GTN incurred to construct, own, and operate the Carty lateral, not the volume of gas elected.

Q. Please summarize PGE's position on Staff's proposed Carty lateral adjustment.

A. Staff's proposal fails to provide acceptable supporting arguments and ignores the fact that the Carty lateral firm transmission service agreement is structured to cover GTN's costs of constructing, owning, and operating the pipeline rather than PGE paying a tariffed rate as we do on the GTN mainline. As the Carty lateral was the least cost, least risk option for PGE and its customers, it is inappropriate to reduce PGE's recovery of this prudently incurred cost.

G. Qualifying Facilities

Q. Please describe PGE's proposal to model Qualifying Facilities.

A. PGE proposed a mechanism that would track and true up the actual commercial online dates of newly forecasted Qualifying Facilities (QFs) with the commercial online date used in MONET's NVPC forecast. In other words, on a going-forward basis, PGE proposes to track the actual online dates of all newly forecasted QFs with the purpose of either refunding to, or collecting from customers, the difference between forecasted and actual online dates. This collection (or refund) would then be included with the next scheduled AUT filing. The QF tracking mechanism that PGE proposed is described in detail in PGE Exhibit 300 (Section III, part H, at page 36).

Q. Did Parties have recommendations regarding PGE's proposed methodology?

A. Yes, while OPUC Staff appears to largely agree with PGE's proposed methodology, they do propose the following modifications:

1) PGE should update QF Commercial Operation Dates (CODs) through the final MONET update in each year's Annual Update Tariff proceeding.
2) PGE should file deferred accounting applications under ORS 757.259 to defer the difference between forecasted and actual QF costs to recover or credit the variance in QF costs in the next NVPC proceeding.
3) PGE should also include any cure period payments within the proposed methodology.

Q. What is PGE's position regarding Staff's recommendations.

A. PGE finds Staff's recommendations reasonable.

Q. Did any party opposed PGE's proposed QF methodology?

A. Although neither party to the UE 335 proceeding expressed opposition specific to PGE's proposed QF methodology, AWEC and CUB have a different proposal to address the issue of QFs not achieving their stated COD.

Q. Please summarize CUB's and AWEC's proposal regarding the modeling of QF CODs.

A. Both AWEC and CUB propose that the expected online date of any new QF be adjusted using the Contract Delay Rate (CDR) methodology the Commission approved in PacifiCorp's 2018 Transition Adjustment Mechanism proceeding.

Q. Please describe the CDR method.

A. This method compares the projected COD to the actual COD for all QF projects. All delayed projects would be averaged to produce a three-year rolling average of delays to produce a CDR which would then be applied to new QF CODs in each year's power cost forecast. The CDR would be weighted by QF size.

Q. What arguments do AWEC and CUB present to support their proposal?

A. Their main argument is that, by adopting the CDR method, the Commission would standardize the QF treatment amongst utilities, which will create "a uniform and settled environment with respect to how the impact of the new QFs are assumed in customer rates."[39] Additionally, CUB argues that the CDR will incentivize PGE to be careful in providing accurate CODs in the future by citing a paragraph from Commission Order No. 17-444 stating that "the rolling average CDR should incentivize the company to use the most updated CODs in the future …".[40]

Q. Do you agree with parties arguments?

A. No. We believe that imposing the CDR method simply to standardize the QF treatment amongst utilities is not reasonable and is unfair to PGE. PGE's history regarding QF adoption is significantly different from PacifiCorp's and Idaho Power's and adopting the CDR method would not be the proper solution to resolve the issue of QFs not achieving their projected COD. Moreover, in support of their argument CUB fails to provide the entire context in Commission Order 17-444. The Commission makes the statement CUB cited based on the conclusion that PacifiCorp "seems to not consistently update the CODs in the TAM forecast."[41] This is not the same in PGE's case. As stated in PGE Exhibit 300, PGE performs an internal assessment to determine the likelihood that a proposed project will

[39] AWEC/100 Mullins/20.
[40] Commission Order No. 17-444, page 17.
[41] Commission Order No. 17-444, page 17.

achieve their stated COD and, as this new information becomes available, consistently updates the status of QF PPAs during all applicable NVPC updates.

Q. Would assuming a three-year average of contract delays be a reasonable method for PGE?

A. No. As described in PGE Exhibit 300, PGE does not have sufficient historical information on which to base a three-year average. Only 30[42] QF PPAs were signed by PGE from 1978 (when PURPA was implemented) through year-end 2015. In addition, PGE only had 8 PPAs with a proposed COD in 2016 and 19 PPAs for 2017. None of these PPAs achieved COD by their proposed dates.

Q. Are there other reasons the CDR method is not appropriate for PGE?

A. Yes, we believe this approach does not accurately forecast the actual online delivery dates for new QF contracts. In addition, we believe that the majority of new QFs are more likely to achieve their scheduled COD because executed PPA agreements are being aggregated and sold to large organizations that have stronger balance sheets and greater ability to overcome solar tariffs and timing challenges.[43] If the CDR method were adopted, PGE would potentially be harmed because using QFs that had projected CODs in 2015, 2016, and 2017 would result in an extremely high CDR, which would be applied on a significantly larger number of QF PPAs (58 in 2019) that are more likely to achieve their projected COD.

Q. Who should bear the risk of QFs not achieving their projected COD?

A. Given the obligation under federal and state law to provide a market for electricity produced by small power producers and generators, we believe that neither PGE nor its customers

[42] In PGE Exhibit 300 PGE inadvertently stated that 26 QF PPAs were signed between 1978 and 2015.
[43] Timing challenges are mostly related to Investment Tax Credits which will begin to phase-down starting 2020.

should bear the risk of forecasting an online date of delivery. Adopting the CDR method would potentially impose more of the risk of QFs not meeting their expected COD on PGE because a very high CDR derived from an extremely limited sample size would be applied to a large number of QF PPAs that are more likely to achieve COD.

Q. Would PGE recover the costs associated with these QFs if their COD was delayed by applying the CDR through the PCAM?

A. Probably not. As a potential collection from customers through the PCAM would not be triggered before actual NVPC exceeds the final forecast by over $30 million, it is unlikely that PGE would recover any difference in power costs and bear the full risk if using the CDR methodology.

Q. Was the CDR the only method CUB proposed in PacifiCorp's TAM?

A. No, CUB also proposed an annual QF deferral. In support of their proposal in UE 323, CUB stated that an annual QF deferral "…allows for full [QF costs] recovery but ensures that over recovery does not happen." PGE agrees with CUB and believes that this method is more appropriate to fix the issue regarding QF timing issues. Consequently, PGE's proposed QF tracking mechanism has its foundation in CUB's annual QF deferral proposal in UE 323.

Q. Why is the QF tracking mechanism a more appropriate method to address the issue of QFs not achieving their projected COD?

A. PGE's proposed QF tracking mechanism provides the simplest, most straightforward, and most accurate method for ensuring that accurate online delivery dates are properly reflected in customer prices. In contrast, the CDR method will not be as simple, straightforward or accurate, and is likely to have implementation issues. The QF tracking mechanism ensures that neither PGE nor its customers will bear the risk of QF PPAs not meeting their stated

COD because PGE will track and true-up the actual commercial online dates of newly forecast QFs with the purpose of either refunding to, or collecting from customers, the difference between forecasted and actual online dates.

Q. Please summarize PGE's position regarding this issue?

A. PGE stands by its initial proposal because we believe it is the most appropriate and fair method to address the issue of QFs not achieving their projected COD for both PGE and for customers. Neither PGE nor its customers would bear the risk of QFs not achieving their projected COD.

H. Other Items

1. <u>North Mist Expansion Project</u>

Q. Did Staff raise any issue regarding PGE's modeling of the North Mist Expansion Project (NMEP) in the 2019 NVPC forecast?

A. No, Staff reviewed the NMEP modeling and found the forecast expense reasonable.

Q. Does Staff have any recommendation regarding the NMEP?

A. Yes, Staff recommends that PGE continue to update the in-service date of the NMEP in subsequent 2019 NVPC updates through the final NVPC update scheduled for November 15, 2018.

Q. Do you agree with Staff's recommendation?

A. Yes. PGE receives weekly and monthly NMEP construction status reports from NW Natural, which we will use to update the expected project in-service date up to our final NVPC update.

2. BPA Wheeling Rate

Q. Please summarize AWEC's proposal regarding the BPA Wheeling Rates.

A. AWEC recommends that PGE does not escalate BPA wheeling rates, arguing that it is premature to make any assumptions regarding the outcome of BPA's 2020 (BP-20) rate case. AWEC's recommendation would reduce the 2019 power cost forecast by approximately $0.9 million.

Q. Why does AWEC believe it is too early to assume an increase in the BPA wheeling rate in 2019?

A. AWEC's argument is based on the outcome of BPA's 2018 rate case (BP-18) that resulted in a decrease to BPA's Point-To-Point (PTP) transmission rates.

Q. Is this a valid reason to keep the BPA wheeling rate projection flat?

A. No. The reduction of PTP rates in BP-18 was an anomalous outcome that occurred due primarily to a restructuring of BPA's debt and the reduction in cost recovery for financial reserves. These circumstances will not exist in BP-20. PGE's view is that it is unrealistic to use a single year as a basis for arguing that wheeling rates will not increase in BP-20.

Q. How did PGE estimate the BPA wheeling rate for the period October 2019 through December 2019?

A. PGE estimated wheeling rates for the period October 1, 2019 through December 31, 2019 (part of BP-20) based on the current rate multiplied by the average rate escalation for the eight BPA transmission rate case periods starting with 2002. However, PGE's proposal in the NVPC proceeding is to use the most current available BPA information regarding their FY2020 wheeling rates prior to our final NVPC update.

Q. Did BPA provide a wheeling rate forecast via its Integrated Program Review (IPR) published June 7, 2018?

A. No. BPA did not provide any specific information regarding their wheeling rates forecast. BPA, however, states that their goal is to keep their spending flat in nominal terms to BP-18 levels for both capital and expense for the forward years 2020-2021.

Q. Is this reason sufficient to maintain BPA wheeling rates flat in the forecast?

A. No. Although BPA's goal is to maintain current spending levels, it does not necessarily mean that wheeling rates will not increase. The expense and capital levels determined in BPA's IPR process are just one component of the costs and factors used in setting wheeling rates. BPA also considers several other assumptions in the rate-setting process such as: capital investment forecasts, loads, resources, market prices, and risk mitigation. Any of these components could cause an increase in BPA's wheeling rate.

Q. Do you have any other comments regarding keeping BPA wheeling rates flat?

A. Yes. BPA wheeling rates include a PTP transmission service rate, an SCD rate, and a Southern Intertie (IS) transmission service rate. In BP-18, although the PTP rate decreased, the SCD charge, which is an adder on every kilowatt that the PTP rate applies to, actually increased, resulting in an overall wheeling rate increase.

Q. Please summarize PGE's response to AWEC's proposed adjustment.

A. PGE disagrees with AWEC's proposal as it is not realistic to assume there will be no change in BPA PTP and SCD wheeling rates during their BP-20 rate based on BPA's 2018 rate case outcome. As stated above, this is an anomalous result that is not expected to occur in BP-20. We propose to maintain our current wheeling rate projection and to update based on any forecasts BPA might make public before PGE's November NVPC update.

3. <u>Independent Code Review</u>

Q. Please summarize CUB's issue regarding an independent code review.

A. CUB proposes that an independent consultant be engaged to review PGE's MONET model in order to suggest potential maintenance of the model.

Q. What is PGE's response to CUB's proposal on this issue?

A. While PGE is not opposed to CUB's request, we believe there are a number of issues that CUB, PGE, and other parties would need to address before conducting such a review. PGE agrees with CUB that MONET is a relatively complex modeling environment. As such, reviewing the entirety of MONET's code, which might involve reviewing the entirety of MONET's inputs and outputs as well, could involve a considerable amount of time and result in a substantial cost to customers. Therefore, prior to conducting such a review, there would need to be agreement on the scope, cost, time commitment, and goals of such a review. Additionally, agreement on and the selection of a consultant could take time.

Q. Does PGE believe there are any "bugs" in the MONET model?

A. No. PGE has a team of experts that review and validate <u>all</u> inputs and outputs within the MONET model. When unexpected results occur, they are thoroughly analyzed and reviewed prior to any official NVPC filing. If no reasonable justification or solution can be found to address unexpected results, as was the case for the third-party PNCA Headwater Benefits Study (HWBS) in PGE's 2018 NVPC filing, PGE will wait to include any update or enhancement until a resolution can be found.

Q. Can you address CUB's concerns on the removal of unused spreadsheets?

A. Yes. Unused spreadsheets in MONET are related to currently unused MONET source code that uses those spreadsheets. We originally built MONET in the 1995-1996 timeframe to do several functions, including fundamental economic market electric price forecasting by area and hub in the WSCC (now Western Electricity Coordinating Council), long-term economic valuation studies of plants, long-term economic capacity expansion and attrition/retirement studies, scenario analysis, and NVPC forecasting. Since approximately the 2000-2002 timeframe, we have used only the NVPC forecasting function in MONET. All of the input and output spreadsheets used by the code that performs the other functions are still present but unused. To make it easier for current users to identify the input spreadsheets that are used by MONET for NVPC forecasting, we shaded those tabs green several years ago. Removing them might require code modification if the code expects them to be present. We agree that some clean up could be beneficial in the long-term.

Q. Can you address the issue of currently unused source code in MONET?

A. Currently unused code in MONET comes from two main sources, functionalities of the original MONET model that are not used for NVPC forecasting, and code left from various code enhancements over the years. Code related to the original functionalities, such as capacity expansion, is part of the original MONET structure and could be removed if desired. To do this would likely require either a re-write of MONET from scratch using only the currently used logic, or incremental removal of unused code in stages, testing NVPC functionality at each stage. Either process may be time consuming but could be done. It would be good to decide for certain that the original functionalities would never be used again before removing them.

Q. What about unused code left from various code enhancements over the years?

A. In general, when making a code enhancement to MONET, the prior source code is left within the model but deactivated with a ‘switch’. From a practical standpoint, this switch-ability is necessary to be able to switch the code enhancement in and out, run the model, enter the NVPC results into the step change log, and validate the results. Usually we need to perform the switching operation repeatedly in drafts during the process leading up to the February initial filing. Also, if there is a desire to revert to the prior code after the filing, we can reverse the enhancement using the switch. After enough time, experience, and satisfaction with the code enhancement, we could decide there is no value in reverting to the old code and we could remove it. We would want to consider "how long is long enough?" and "what's the value and priority of removing the old code?" Any code removal must be done carefully and tested, and we believe it should be done in consideration and coordination with what we do with the unused code related to the functionalities of the original MONET model that are not used for NVPC forecasting.

Q. What does PGE propose to address CUB's issue?

A. In order to address CUB's concerns on this issue PGE proposes the following:

1. PGE will host a workshop to provide CUB and other interested parties with an in-depth overview of the MONET model going over the theory, history, assumptions, and inputs included within the model.
2. During this workshop, PGE proposes to work collaboratively with parties to address any outstanding concerns they might have.
3. If concerns remain after completion of the workshop review, PGE will determine with CUB, Staff, and AWEC the proper parameters requiring further analysis and will work with parties to identify a third-party consultant(s) who can address the remaining concerns.

4. Finally, PGE proposes a deferral mechanism be implemented to recover any costs involved in conducting the third-party review if needed.

4. <u>Capacity Agreement</u>

Q. Please describe the capacity agreement included in PGE's 2019 initial NVPC forecast.

A. PGE has entered into a PPA with a counterparty for firm capacity totaling 100 MW and backed by a physical resource. This contract is one of the top five scoring offers presented in Docket No. UM 1892.[44] As described in PGE Exhibit 300, PGE's 2016 Integrated Resource Plan, filed in November 2016, identified a capacity need up to 850 MW in 2021. Subsequently, the capacity need was reduced to 561 MW and, based on feedback from the Commission, OPUC Staff, and stakeholders, PGE pursued bilateral negotiations with owners of existing regional resources to fill its capacity need.

Q. Please summarize Staff's proposal regarding the capacity agreement included in Step 0H of PGE's 2019 initial NVPC forecast.

A. Staff recommends excluding the incremental cost of this contract from PGE's 2019 NVPC forecast and that PGE provide Staff access to the financial analysis supporting the selection of the top five contracts in PGE's bilateral negotiations.

Q. What is the basis of Staff's adjustment regarding the capacity agreement?

A. Staff proposes this adjustment "in an abundance of caution"[45] because PGE did not provide to Staff the financial analysis supporting the contract selection. In addition, Staff is also questioning the timing of this agreement since the capacity need identified in PGE's 2016 IRP is for 2021 and the seasonal capacity contract will start in 2019.

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[44] PGE filed a request to waive the Commission's Competitive Bidding Guidelines that call for a competitive bidding process for resources greater than 100 MW and a term of more than five year.
[45] Staff/300, page 22, lines 10-11.

Q. Why has PGE not yet provided the financial analysis supporting the contract selection within this proceeding?

A. The financial analysis that Staff requested is highly confidential information that could impact the market position of the energy suppliers PGE engaged with in bilateral negotiations to fill the resource deficiency identified in the 2016 IRP.

Q. Did OPUC Staff and other stakeholders have the opportunity to review the prudency of this contract?

A. Yes. This contract was one of the five offers that resulted from PGE's bilateral negotiations with owners of existing regional resources to fill its capacity need. OPUC Staff and other stakeholders fully reviewed and vetted the selection of these offers in Docket No. UM 1892.

Q. What was Staff's conclusion in UM 1892 regarding PGE's bilateral negotiation for capacity resources?

A. In Commission Order No. 17-494, Staff's recommendation stated that they generally find that PGE's bilateral negotiations: "could result in contracts that limit long-term energy costs for PGE", "were based on Commission direction", "complemented PGE's acknowledged IRP", "were flexible and negotiated mutually beneficial agreements", and "were conducted in a manner that was sufficiently transparent, understandable, and fair under the circumstances of this particular filing." Staff finally recommended that the Commission grant PGE's request in UM 1892 because "PGE has demonstrated good cause and met all five of Staff's reasonableness conditions."

Q. Why did PGE acquire this resource in 2019, two years sooner than its 2021 resource deficiency?

A. PGE entered into this PPA to replace an existing seasonal capacity contract with the same provider. The current agreement will expire in 2019 and there was no option to put a hold on the new contract between 2019 and 2021. Additionally, the evaluation of the bilateral negotiations that was included in UM 1892 looked at the bid costs compared to the energy, capacity, and flexibility benefits the resource provided. The contract or resource was only provided a capacity benefit for those years where, at the time of evaluation, the company was projecting a capacity need. With this methodology in place, this particular resource was one of the top five performers.

Q. Will this resource be useful to PGE in meeting customer reliability needs prior to 2021?

A. Yes. PGE has called on this agreement and is filling the capacity need to provide reliable service to customers during peak conditions.

Q. Do you agree with Staff recommendation?

A. No. While we agree to and are in the process of providing Staff with access to the financial analysis that resulted in the selection of the top five offers, we are opposed to excluding the capacity agreement from our 2019 NVPC forecast. This contract was fully reviewed and vetted by the Commission and stakeholders in UM 1892 and useful to PGE in providing reliable service to customers during peak conditions**.**

5. Headwater Benefits Study

Q. Please summarize Staff's issue regarding the HWBS update.

A. Pursuant to a technical conference discussion on April 17, 2018, PGE provided Staff on May 23, 2018 with an electronic copy of material in support of PGE's proposed change to the NVPC forecast associated with correcting and including the results of the 2016-2017 HWBS. This material included summary documentation, supporting files, and other documentation PGE expects to include in the July NVPC update. According to Staff Exhibit 100, they are continuing to review the information and currently have no position on PGE's request.

Q. Is PGE still planning to include this update in its July NVPC update?

A. Yes. PGE will be updating its July filing with the corrected 2016-2017 HWBS, which is consistent with the information provided to Staff on May 23, 2018.

III. Summary and Conclusion

Q. In closing, please summarize your proposals regarding the issues identified by parties.

A. With the exceptions discussed above, we recommend the Commission reject the parties' positions regarding the issues identified. The parties largely propose adjustments based on incomplete and faulty analysis and inaccurate or misguided assumptions, with the purpose of ensuring that PGE under-recovers its prudently incurred NVPC for 2019.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1401	Staff's response to PGE Data Request No. 007
1402C	March 19, 2012 Hedging Presentation to OPUC
1403C	Summary of Mid-Term Strategy Program
1404	GTN Historical Pressure

Date: June 15, 2018

TO:
PATRICK G. HAGER
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FROM: Lance Kaufman
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 335 - PGE Data Request filed June 5, 2018 from Greg Batzler

Data Request No 07:

7. Please refer to Staff Exhibit 300, Staff Work Paper "COB Margins Staff CONF_05.30.18":
    a. Please confirm that the source for the data in "Sheet7", columns B to M is the "#2014-2016_MonthlyCOBAvg-2018 AUT_1.14.17 - Copy" work paper that PGE provided in its initial NVPC filing in UE 319. If the answer is yes, please explain why the data in "Sheet7", columns K to N includes prices starting 2004- 09 whereas the data source only includes 2014-2016 data. If the answer is no, please provide the source of all the data.
    b. Please explain why the data presented in "Sheet7" that references PGE's work paper "#2014-2016_MonthlyCOBAvg-2018 AUT_1.14.17 - Copy" includes Mid- C prices, whereas PGE's original work paper does not include any Mid-C data. Please also provide the source of these data.
    c. Please provide the source of the data provided in "Sheet7", columns L and M.
    d. Please explain why the data in "Sheet7", column S is calculated in absolute values.
    e. Please confirm that prices in "Sheet7", columns K to N are the weighted average of ICE Day-Ahead settlement prices. If not, please describe the data provided and the basis for their use.
    f. Please provide the source for the data included in the "MidC" tab of the referenced work paper.
    g. Please provide the underlying formulae calculating the values in "Sheet7", columns L and M.

h. Please confirm that transaction data provided in “Sheet7”, columns A:C include both Day Ahead Market (DAM) and Real-Time Market (RTM) transactions. If you answer is yes, please explain why the Mid-C reference prices in column D only include PowerDex hourly market prices and why it is appropriate to calculate the margin on DAM trades in column E using the hourly index that is based on RTM transactions.

Staff Response No 07:

7.

a. The data in columns B and C were included in both “#2014-2016_MonthlyCOBAvg-2018 AUT_1.14.17 – Copy” from Docket No. UE 335 located in the folder “Confidential\Vol 5 - Contracts\COB Trading Margins”. The data in column D were provided in Docket No. UE 319 PGE Response to OPUC DR 564 Attachment B. Column E through K are calculated values or empty. Column L and M were collected by Staff from the intercontinental exchange in 2017.
b. Staff’s model relies on valuing COB transactions relative to Mid-C transactions. This is because the COB market is not represented in the Monet model, while the Mid-C market is. The Mid C prices were added to calculate the value of the COB transactions. Please refer to Docket No. UE 319 PGE Response to OPUC DR 564 Attachment B.
c. These data were collected by Staff from the intercontinental exchange in 2017. The data no longer appear to be available.
d. This value is calculated as an absolute value because the value of a transaction between COB and Mid C depends on the absolute size of the spread.
e. Staff no longer has access to the ICE source data for these values.
f. Please refer to Docket No. UE 319 PGE Response to OPUC DR 564 Attachment B.
g. These formulae are not available.
h. The referenced data were created by PGE and provided in the file “#2014-2016_MonthlyCOBAvg-2018 AUT_1.14.17 – Copy”. Staff cannot confirm the content of these data because Staff did not generate the data. Staff’s methodology is appropriate because real time prices provide a reasonable approximation of day ahead prices and because Staff does not have access to day ahead market price indexes for COB and Mid-C.

Bin	Frequency	Cumulative %
605	0	0.00%
620	0	0.00%
635	17	0.17%
650	23	0.41%
665	41	0.83%
680	165	2.52%
695	447	7.11%
710	674	14.02%
725	726	21.47%
740	1008	31.81%
755	1274	44.88%
770	1541	60.69%
785	1228	73.29%
800	1058	84.14%
815	742	91.75%
830	655	98.47%
845	143	99.94%
860	6	100.00%
More	0	100.00%