Oregon
Kate Brown, Governor

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June 25, 2019

Via Electronic Filing and US Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 359 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2020 Annual Power Cost Update Tariff (Schedule 125)

Enclosed for electronic filing are Staff Opening Testimony, Certificate of Service and UE 359 Service List.

Exhibits 100 pages 9 and 10 are confidential; Exhibits 101-102
Exhibits 200 pages 4 and 5 are confidential; Exhibits 201-202 and 203 has one CONF Excel
Exhibits 300 page 17 is confidential; Exhibits 301-304 where Exhibit 303 is Confidential.
Exhibits 400 pages 2, 3, 4, and 5 are confidential;
Exhibits 401 – 402 and
Exhibit 403 is a mix of confidential and non-confidential:
Pages 1 to 13 are non-confidential
UE 359 Exhibit 403 Zarate OPUC DR 001_Attach A (electronic)

Pages 14 to 26 are confidential- see breakdown:
UE 359_OPUC DR 001_Attach B_CONF
UE 359_OPUC DR 004_Attach A_CONF
UE 359_OPUC DR 009_Attach A_CONF, Attach B_CONF, Attach C_CONF, Attach D_CONF (zip file); and Attach E_CONF
UE 359_OPUC DR_017 Attach B_CONF
And finally Pages 27 to 30 are non-confidential

Per PGE's approval, this filing of both confidential and non-confidential will be uploaded to Huddle. The filing will be available to Parties who have signed Protective Order No. 19-112.

/s/ Kay Barnes
Kay Barnes
kay.barnes@state.or.us

CERTIFICATE OF SERVICE

UE 359

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 25th day of June, 2019 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
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CASE: UE 359
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

June 25, 2019

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a senior economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I provide a summary of Portland General Electric Company (PGE)'s 2020 Automatic Update Tariff (AUT) filing and Staff's proposed adjustments. I also discuss Staff's analysis of PGE's load forecast, Production Tax Credit (PTC) forecast and wind capacity factors, PGE's Wheatridge Renewable Energy Facility, and Colstrip modeling.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/102, which includes the Company's response to Staff DR Nos. 39 and 42.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF STAFF'S REVIEW OF PGE'S 2020 NVPC FILING

Q. Please explain PGE's 2018 NVPC filing.

A. Commission Order No. 08-505 authorized PGE's AUT, which allows for an annual adjustment to PGE's rates that accounts for the forecasted changes in the coming test year's NVPC. When filed as a stand-alone case, the AUT is filed by April 1 of the preceding year and includes updates to a pre-specified set of data parameters. When filed as concurrently with a general rate case the Company is also able to propose changes to the methodology.

Q. Apart from the standard parameter updates, is the Company proposing any changes from the 2019 NVPC filing?

A. Yes, the Company has proposed the following changes:

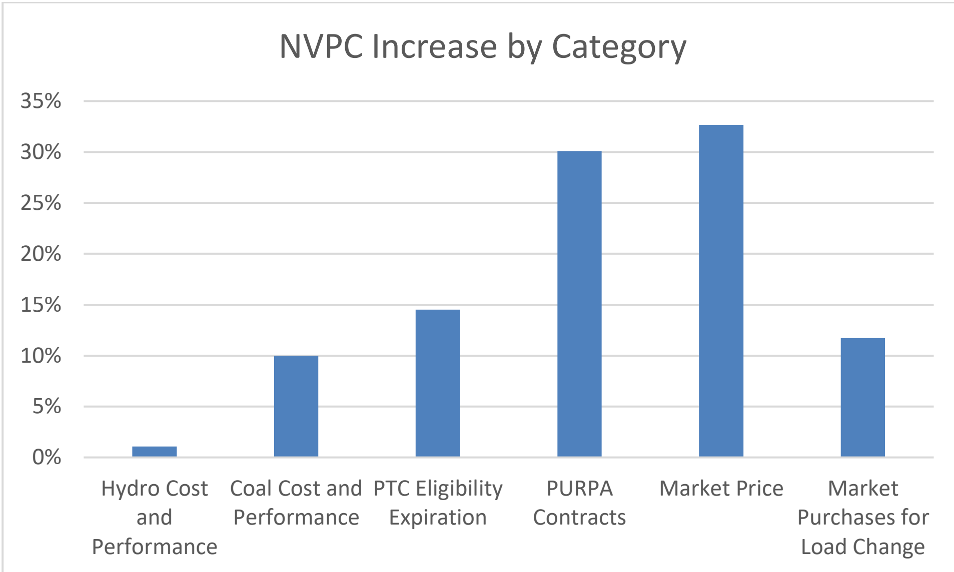
1. Adjust the manner in which it forecasts EIM benefits;[1]
2. Apply a transmission deration on volumes at COB;[2] and
3. Adjust dispatch at Boardman in light of closure at the end of the year.[3]

Q. Please summarize PGE's 2020 AUT filing.

A. The Company's initial filing requests a 2020 Net Variable Power Cost (NVPC) of $422 million, which represents an increase of approximately $60.5 million compared to the final 2019 NVPC.[4] This equates to an increase of $2.93/MWh or 15 percent from $19.60/MWh to $22.53/MWh.[5] Figure 1 below shows the increase percentage by category.

[1] PGE/100, Niman et al./8.
[2] *Ibid.* at 14.
[3] *Ibid.* at 17.
[4] *Ibid*. at 1.
[5] *Ibid.* at 32.

Figure 1



Q. What topics will Staff testimony address?

A. Staff discusses the following issues in our opening round of testimony:

(Staff/100 Gibbens)
1. Load Forecast
2. PTC Forecast and Wind Capacity Factors
3. Wheatridge
4. Colstrip

(Staff/200 Soldavini)
5. California-Oregon Border Margins
6. Boardman Operations 2020

(Staff/300 Enright)
7. Western Energy Imbalance Market
8. Wholesale Transactions

(Staff/400 Zarate)
9. Qualifying Facilities Cost
10. Standard Inputs

ISSUE 1. LOAD FORECAST

Q. What is PGE's load forecast for 2020 retail load?

A. PGE's initial 2020 retail load forecast is 19,657 GWh.[6] This is roughly a one percent increase from forecasted 2019 deliveries.

Q. What are the primary drivers of the increase in load in the 2020 AUT?

A. The forecasted increase in total load is due to increases in the Residential and Industrial customer class loads."[7]

Q. How did Staff analyze this issue?

A. Staff reviewed the Company's workpapers related to load forecast to ensure proper calculation of the impact. Staff focused on the load forecasts that exhibited the largest changes. Staff traditionally does not produce a full model replication of the Company's load forecast in every power cost filing, but reviews the Company's forecast to determine whether it is reasonable on a short-term basis (for the AUT test year). Staff notes that the Company has opposite incentives in load forecast biases between a general rate case (GRC) and the AUT. In a GRC, there is an incentive to under forecast load to put upward pressure on the amount of revenue the Company must collect to cover its Revenue Requirement. In the AUT, there is an incentive to over forecast load to put upward pressure on the amount of power that must be acquired to serve load. As such, one of Staff's main concerns is in verifying that the same methodology is used in power cost filings as in a GRC where a more extensive

[6] PGE/100, Niman et al./29,
[7] *Ibid*.

review of the Company's forecast is performed. Additionally, Staff notes that the Company is preparing to file its 2020 IRP, and as part of both the AUT and the IRP Staff will continue to monitor and evaluate the load forecast.

Q. Does Staff propose an adjustment to Load Forecasting?

A. No, at this time Staff has no proposed adjustments for this issue.

ISSUE 2. PTC FORECAST AND WIND CAPACITY FACTORS

Q. Please provide a background of this issue.

A. In UE 319 Staff proposed a change to the wind capacity factor calculation methodology.[8] Staff's goal was to share generation risk between shareholders and rate payers. Instead of using only actual generation to calculate the capacity factors, Staff proposed to use a split of the "P50 forecasts"[9] created at the time of project development and actual generation from the projects to determine the capacity factor for PGE's owned resources (50/50 methodology). This methodology:

- Splits wind generation risk between customers and shareholders;
- Incents utilities to accurately forecast wind capacity factor of new projects; and
- Makes the RFP process more competitive and improves outcomes for customers.

The issue was ultimately settled as part of a larger settlement of all issues for PGE's 2018 AUT, which included a dollar adjustment to settle a number of issues.[10] This resulted in no clear resolution for the wind capacity factor issue however. In UE 335, Staff again proposed a similar change for PGE's 2019 AUT. Like UE 319 the previous year, a dollar adjustment was made in

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[8] UE 319 Staff/200, Kaufman/11.

[9] When probabilistic Monte Carlo type evaluations are adopted, this is a statistical confidence level for an estimate. P50 is defined as 50 percent of estimates exceed the P50 estimate (and by definition, 50 percent of estimates are less than the P50 estimate).

[10] Order No. 17-384.

conjunction with several outstanding issues, but no change to methodology was made.[11]

Q. How does PacifiCorp forecast wind capacity factors in the TAM?

A. UE 339, PacifiCorp's 2019 TAM, had a similar issue, where parties worked to develop a methodology that would properly align customer and shareholder incentives. In the stipulation associated with that docket, the Company agreed to use the 50/50 methodology on a one-year basis.[12] In this year's filing, PacifiCorp has proposed the continued use of the 50/50 methodology moving forward.[13] Staff noted in its opening testimony that, "the 50/50 approach is a proper way to share performance risk between ratepayers and shareholders, generally, because it provides a good balance between aligning Company and ratepayer incentives in a RFP and forecast accuracy."[14]

Q. What is Staff's proposal for wind capacity factor methodology in this filing?

A. Staff continues to believe that the 50/50 methodology is a proper way to share generation risk. When only actuals are used in power cost filings, utility owned projects receive an unfair advantage in an RFP. Third-party projects must account for generation risk in their bids, as they assume the risk of unrealized generation and PTCs. Under the current construct, PGE owned projects do not need to account for generation risk as the ratepayer assumes all of it in

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[11] Order No. 18-405.
[12] Order No. 18-421.
[13] UE 356 PAC/100, Wilding/35.
[14] UE 356 Staff/100, Gibbens/14. Staff ultimately recommended a different treatment for EV 2020 projects.

subsequent AUTs. As the State continues to push to raise carbon reduction goals, this methodology becomes more and more important. Staff also notes that this approach would standardize the methodology between the State's two biggest regulated electric utilities; providing similar customer protections for both PGE and PacifiCorp customers.

Staff realizes that this issue has been a point of contention for the past three power cost filings, and so has come up with an alternative recommendation as well. PTC benefits generally equate to roughly 66 percent of the overall project benefit for the first ten years of a wind project. As such, ensuring the proper incentives between Company and ratepayer is more important during this time than in subsequent years. Staff's secondary proposal is to utilize the same methodology as PGE currently uses, but to use ten years of actuals as opposed to five. In the first year of a project, only the P50 forecast would be used. In the second, year one actuals would account for 10 percent of the calculation while the P50 would account for 90 percent. In the third year it would become 80/20 and so on. Although this is not Staff's primary recommendation, it does achieve a balance between sharing generation risk and forecast accuracy, particularly in the most important years of a project's life cycle. Staff notes that this would result in little change to PGE's current plants, but would properly incentivize PGE in future RFPs.

Q. How is generation risk split between customers and shareholders?

A. When the actual capacity factor of wind facilities is lower than forecasted, there are two financial impacts: lost energy value and lost production tax credit (PTC) value. Wind generation has little to no marginal cost. When wind production is lower than expended, PGE has to replace that energy with higher cost sources. Staff previously estimated that the dollar value of lost energy associated with over forecasting wind capacity factors was about **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]** In addition to the lost energy, PGE does not receive the expected PTCs. Staff estimates that the value of the lost PTCs is about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Under Staff's proposal, PGE shareholders will bear a portion of the risk associated with the lost energy value, and customers will bear the risk associated with the lost PTC value. This approach appropriately shares the risk associated with ownership of wind resources between the utility shareholders and customers.

Q. How does Staff's proposal incentivize utilities to accurately forecast wind generation?

A. Under PGE's method, the Company updates the wind capacity factor every year. In addition, actual wind generation is incorporated in the Power Cost Variance Mechanism (PCVM). The PCVM includes mechanisms that prevent 100 percent of costs passing through to customers. Thus the only exposure the Company has to wind generation forecast risk is through the difference between the year-ahead wind forecast and the actual wind generation. Staff's approach makes the Company accountable for its resource decision. Because of this the Company will be more likely to evaluate and vet the wind forecasts.

Staff's first alternative does benefit the Company in the case of forecasts that are too low. However under both alternatives, customers are guarded against the risk of a low forecast through the competitive bidding process. If the Company under-forecasts wind generation, competing bids will be more likely to be selected.

Q. How does allowing utility shareholders to share in generation risk make the RFP process more competitive?

A. PGE's recent generation RFPs have primarily resulted in PGE ownership of new resources. If shareholders are exposed to some of the generation risk associated with ownership, the utilities will incorporate generation risk into their bids. This is a risk that other bidders already bear. Staff's proposal will bring the Company ownership in line with non-company ownership bids. As a result, the competitive bidding process will be more effective.

A more competitive bidding process will benefit customers. PGE's recent self-owned resource acquisitions have faced substantial problems, either with lower than expected benefits or higher than expected costs.

Q. Why is it fair for PGE shareholders to share in the risk of wind generation?

A. PGE has invested $1.7 billion in wind facilities. At PGE's current capital structure and cost of equity that represents $82 million dollars per year in profit for PGE shareholders. Staff's proposal reduces power costs by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff's alternative approach would have limited impact on current rates, but would improve the structure of wind forecasts for future Company-owned wind plants.

ISSUE 3. WHEATRIDGE RENEWABLE ENERGY FACILITY

Q. Please provide a background on this issue.

A. Following the conclusion of the Company's 2016 IRP and 2018 Renewable RFP, construction is underway to build a 300 MW wind facility called Wheatridge Renewable Energy Facility. PGE will own 100 MW of the total capacity and purchase the power of the other 200 MW through a long-term PPA. Construction of the plant is expected to conclude in December of 2020 in time to qualify for 100 percent of the PTCs. The project will also include 50 MW of solar and 30 MW of battery storage expected to be online in 2021. PGE did not include any benefits associated with the generation from the project in its 2020 AUT.

Q. Does Staff have any concerns regarding the Company's decision to exclude Wheatridge from the 2020 AUT?

A. Yes. In addition to legal concerns, which Staff will address in briefing, Staff has another concern about the Company's decision to not include the NPC and PTC benefits in the 2020 AUT. The concerns mirror concerns Staff had in the 2019 TAM and 2020 TAM when PacifiCorp proposed to exclude the NPC and PTC benefits from its EV 2020 projects. Staff is concerned that the Company's proposed ratemaking treatment is one-sided and inconsistent with Commission policy and precedent regarding the ratemaking treatment for variable costs and benefits for RPS-compliant resources, including PTCs.

Commission policy and precedent regarding ratemaking treatment for costs and benefits of RPS compliant resources.

In 2007, SB 838 was passed, creating Oregon Renewable Portfolio Standard (RPS). SB 838, Section 13, provides for the recovery of "all prudently incurred costs associated with compliance with a renewable portfolio are recoverable in the rates of an electric utility."[15] SB 838 further directed the Commission to establish an automatic adjustment clause or another method for timely recovery of RPS compliance costs.[16] The Commission subsequently opened docket UM 1330, which investigated the adoption of an automatic adjustment clause or other method for timely recovery of costs as required by SB 838. The Commission adopted the non-contested stipulation filed by PGE, PacifiCorp, Oregon Staff, CUB and ICNU.[17] The stipulation authorized PGE and PacifiCorp to implement RAC tariffs by which they could recover the costs associated with RPS compliant resources. The stipulation approved by the Commission states that the revenue requirement recovered pursuant to the RAC includes:

- *The return of and on capital costs of the renewable energy source and associated transmission;*
- *Forecasted operation and maintenance costs;*
- *Forecasted property taxes;*
- *Forecasted energy tax credits; and*

[15] Now codified at ORS 469A.120(1).
[16] ORS 469A.120(2).
[17] Order No. 07-572 at 10.

- *Other forecasted costs and cost offsets authorized by SB 838* ***and not captured in the Utility's annual power cost update***.[18]

Therefore, the Commission adopted a stipulation that required costs and benefits of RPS compliant resources not otherwise recovered in the utility's annual power cost proceedings to be recovered in the RAC. In short, the RAC is intended to cover items not otherwise included in the AUT.

Subsequent to Order No. 07-572, the Commission opened a second investigation—Docket UM 1662—which considered the recovery of variable costs associated with RPS compliance (i.e., RPS compliance costs subject to forecast in the TAM or AUT, and the PCVM).[19] In that case, PGE and PacifiCorp argued that variations in PTCs and other variable costs and benefits should be recovered on a dollar-for-dollar basis, rather than on a forecast basis and subject to the PCVM.[20] Staff, CUB, and ICNU argued that ORS 469A.120(1) did not require dollar-for-dollar recovery of all RPS related costs and benefits.[21] The Commission adopted Staff's, CUB's, and ICNU's position, concluding that certain RPS costs would not be subject to dollar-for-dollar recovery and would need to be recovered through general ratemaking.[22] This includes variable costs and benefits of RPS compliance.

[18] Order No. 07-572 at 3 (emphasis added).
[19] Order No. 15-408.
[20] Order No. 15-408 at 2-3.
[21] *Ibid*.
[22] Order No. 15-408 at 6-7.

In 2016, the Oregon Legislature passed SB 1547, directing each public utility to forecast, on an annual basis, projected state and federal production tax credits received by the public utility due to variable renewable electricity production, and directing the Commission to allow those forecasts to be included in any variable power cost forecasting process established by the Commission.[23]

In response to this directive, in its 2017 AUT, PGE proposed to include the full effect of PTC generation in its NVPC forecast. This removed the credit from base rates and made it subject to the PCVM true up. The Commission adopted this ratemaking treatment.[24]

The Company's failure to include NPC and PTC benefits for Wheatridge is inconsistent with the ratemaking treatment for PTCs agreed to by the Company, and adopted by the Commission, in the Company's 2017 AUT. The Company's proposed approach is also inconsistent with the Commission's direction in Order Nos. 07-572, 15-408 and 16-419. Furthermore, Staff will reserve this issue for briefing, but notes that it questions whether the Company's proposal is consistent with ORS 757.264 and ORS 757.269.

Q. What is Staff's recommendation for the treatment of Wheatridge?

A. Staff recommends that Wheatridge variable costs and benefits (for both the PGE-owned and PPA portions) be generally reflected in AUT proceedings and therefore included in the forecast for the 2020 AUT. This treatment is

[23] This provision is codified as ORS 757.264.
[24] Order No.16-419.

consistent with PacifiCorp's treatment of EV 2020 benefits for the 2019 TAM and past Commission policy and precedent. Staff believes the AUT is capable of handling the NPC and PTC impacts of the Wheatridge project. PGE is able to encompass all non-Schedule 122 costs and all of the direct and indirect benefits, on a forecast basis, consistent with the ratemaking treatment for all other wind projects included in Oregon rates.

ISSUE 4. COLSTRIP

Q. Please provide a background for this issue.

A. The Company's current contract with Westmoreland Coal Company, the owner of the Rosebud mine that supplies coal for the Colstrip plant, expires at the end of 2019.[25] A new coal supply agreement is still in the negotiation phase and the prices for coal at Colstrip are subject to change in future AUT updates, based upon these ongoing negotiations.[26] Until a new contract is in place, the Company is maintaining the current contract price in the 2020 AUT.

Q. Does Staff have an adjustment or recommendation regarding third-party coal supply costs?

A. No, Staff has no adjustment at this time, and is actively monitoring the Company's ongoing negotiations and awaiting updates on the issue before making a recommendation. The negotiations are highly confidential, but Staff and the Company have been working closely together to so that Staff stays apprised of any new developments. Staff notes that it retains the ability to review the final contract for prudence, whether in this proceeding or in next year's AUT proceeding if the contract is finalized after the close of the record in this case.

Q. Does this conclude your testimony?

A. Yes.

[25] PGE/100, Niman et al./34.
[26] Staff/102, Gibbens/1 (PGE's response to Staff DR No. 39).

CASE: UE 359
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

June 25, 2019

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UE 359
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 25, 2019

June 13, 2019

TO: Scott Gibbens
Public Utility Commission of Oregon

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 039
Dated May 30, 2019

Request:

Please provide an update on the ongoing contract negotiations to secure a coal supply contract for the Colstrip plant.

Response:

PGE is actively engaged in coal supply contract negotiations in conjunction with the other five Colstrip plant co-owners. Given the confidential nature of these negotiations, PGE is unable to disclose any further details. Once parties have achieved consensus on the material terms and conditions of a new contract, PGE will provide additional details.

June 13, 2019

TO: Scott Gibbens
Public Utility Commission of Oregon

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 042
Dated May 30, 2019

Request:

What is the latest date PGE is expecting to update the coal price for Colstrip in the 2020 AUT?

Response:

According to PGE's Schedule 125, PGE can update new fuel contracts up until its final November 15th filing. However, PGE will likely file an update prior to this deadline and may be able to provide an estimate based on indicative prices in July.

CASE: UE 359
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 200

Opening Testimony

June 25, 2019

Q. Please state your name, occupation, and business address.

A. My name is Sabrinna Soldavini. I am a Senior Regulatory Analyst employed in the Energy Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support Staff's position on the treatment of California-Oregon Border (COB) Margins and the Boardman plant shutdown as they relate to Portland General Electric Company's (PGE) Automatic Update Tariff (AUT).

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following Exhibits:

- Exhibit Staff/201 – Witness Qualification Statement
- Exhibit Staff/202 – PGE Responses to Staff Data Requests
- Exhibit Staff/203 – PGE Responses to AWEC Data Requests

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. CALIFORNIA-OREGON BORDER (COB) MARGINS

Q. Please provide a background for this issue.

A. The appropriate ratemaking treatment of COB trading margins was first raised by Industrial Customers of Northwest Utilities (ICNU) in UE 294 in connection with the Commission's review of PGE's 2016 AUT. ICNU argued that as PGE sells and purchases energy at the California-Oregon Border and monetizes the spreads between COB and Mid-C prices, this benefit should go to ratepayers as an offset to NVPC. At the conclusion of UE 294, the Commission ordered PGE to propose a methodology to capture, for purposes of the AUT, the value of benefits PGE obtains through transactions at COB made possible by transmission rights paid for by PGE ratepayers.[1] PGE proposed a methodology to capture COB trading margins in its 2017 AUT filing, docketed as UE 308. Staff recommended modifications to that methodology and has continued to advocate for refinements to the methodology in connection with every AUT filing since.

Q. Does Staff have issues with how PGE calculated the COB margin for its 2020 AUT?

A. Yes, although Staff does not propose a specific dollar adjustment. Staff believes the modeling could be more granular. Staff raised this issue in connection with its review of PGE's 2018 and 2019 AUT filings, docketed as UE 319 and UE 335. In Docket No. UE 335 regarding PGE's 2019 AUT, the

[1] Order No. 15-356.

Commission ordered PGE to continue to investigate methods to increase the granularity and improve the modeling of COB margins.[2]

Q. Is it clear to Staff that PGE complied with Order No. 18-405, investigating methods to increase granularity and improve the modeling of COB margins?

A. No, it is not. While the Company is proposing a change to the modeling of COB margins in this docket, it is not clear to Staff that PGE conducted a serious investigation into increasing the granularity of COB margin calculations to more accurately account for hourly variation. In a technical workshop for this docket held on June 4, 2019, PGE noted that while it had studied increasing the granularity, PGE deemed it too complicated and any documentation of such considerations were not saved, and thus not available for review by Staff or other parties. In response to a data request, the Company provided copies of email exchanges between PGE employees in 2018 and 2019 that discuss the need to investigate COB margin granularity. These appear to show some review into increasing granularity, though no descriptions of the workpapers were provided outside of the emails.[3] Staff does not believe this correspondence is tantamount to compliance with the Commission's order.

It is certainly feasible that the outcome of a good faith investigation is to conclude it is impractical to implement modeling changes because they are overly burdensome; however, it is impossible for Staff to verify PGE's

[2] Order No. 18-405.
[3] Staff/203, Soldavini/3 (PGE Response to AWEC DR 31 Confidential Attachment A).

conclusion because there is no formal documentation of PGE's investigation. Staff recommends that the Commission direct the Company to continue its review of potential modeling upgrades and to produce the results in a form that can be reviewed by interested parties.

Q. How does the level of COB margin benefits in the 2020 AUT compare to last year's 2019 AUT?

A. The value included for COB margins was approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in last year's AUT, as compared to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** included in this year's 2020 AUT.

Q. What changes to COB margin calculations is PGE proposing in this docket?

A. PGE is proposing to include a transmission deration on the estimated volume of transactions at COB in 2020 to approximate capacity derations that could limit the Company's transfer capability along the N-S path. The Company states that currently, their model does not factor in potential limits in transfer capabilities at COB and that these derations place real, unaccounted for limits on their ability to transact.

PGE proposes to capture the effect of BPA derations along the N-S path using a three-year rolling average of actual 2016-2018 transmission derations applied by BPA. The transmission deration is then applied when PGE's usage of its transmission rights (296 MW total) is greater than BPA's available capacity.

Q. What is the effect of the change on NVPC?

A. The inclusion of deration along the N-S path increases NVPC by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** with no deration applied to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** with the deration included.

Q. Does Staff have concerns with this proposed change in methodology?

A. Yes. Staff is concerned that the inclusion of the transmission deration underestimates transaction volumes, and therefore underestimates the total benefits. The methodology for calculating COB margins includes the use of 2016-2018 historic transaction volumes. These historic volumes already incorporate any constraints, and therefore an additional adjustment for transmission derations is unnecessary and would double count the effect the derations had on transaction volumes.

Additionally, Staff notes that in response to a data request by AWEC, PGE states the Company has at times had to purchase short-term transmission rights for the opportunity to trade between the Mid-C and the COB power hubs. PGE explains that the "transmission derate proposal in the COB margin calculation method aims at partially recognizing the costs that PGE incurs when purchasing short-term transmission capacity on BPA's N-S transmission path."[4] While Staff recognizes there may in fact be costs associated with such short-term purchases, Staff does not believe PGE has

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[4] Exhibit/203, Soldavini/1.

accurately accounted for those via the inclusion of a transmission deration. Staff will continue to work with parties to determine whether there should be dollar adjustment for costs for short-term transmission purchases.

ISSUE 2. BOARDMAN OPERATIONS 2020

Q. Please provide background for this issue.

A. PGE is set to cease operations at its Boardman plant by December 31, 2020. PGE lists two main challenges it faces in relation to 2020 Boardman operations in this docket: coal supply constraints and coal inventory management. To address the winding down of operations and expected supplies, MONET has been updated accordingly, including the modeling of derations in Q1 and Q3, Trona[5] availability constraints, as well as a 100 percent deration of the plant in Q4 2020. The following sections of testimony will discuss each of these constraints, and their effect to NVPC in more detail.

Coal Supply Constraints

Q. What are the issues resulting in coal supply constraints in 2020?

A. Essentially, PGE states that a confluence of issues has prevented the Company from having sufficient inventories of coal to dispatch Boardman at economic levels in 2020. The two main issues constraining coal supply in 2020 are an inability to be supplied more than 97,500 tons of coal per month on average in 2019 and 2020, and increases in market prices that have led to more economic dispatch of Boardman in 2019, both of which prevent the Company from building onsite inventories in preparation for 2020.[6]

[5] Trona is a compound used to capture sulfur dioxide emissions and is used at Boardman as part of the emissions control process.
[6] PGE/100, Niman – Kim – Batzler/18, Lines 15 through 16.

Q. Please elaborate.

A. PGE notes in its Opening Testimony, that as a result of the Enbridge gas pipeline rupture in October 2018, gas supply in the region was affected in such a way that energy market prices increased enough to exceed Boardman's dispatch costs. This resulted in Boardman being more economic to run and ultimately to increased coal consumption at Boardman during Q4 2018 and Q1 2019. PGE notes forecasted market prices indicate a high likelihood of increased coal consumption at Boardman for much of 2019 as well.[7] This increase in Boardman dispatch levels, combined with coal delivery constraints to Boardman in 2020, lead to a forecasted insufficient level of coal supply to dispatch Boardman at economic levels in 2020.[8]

Q. Why can the Company only receive an average of 97,500 tons of coal per month in 2020?

A. The Company notes that it has tried to increase coal deliveries from both BNSF and Union Pacific, but that attempts have been unfruitful as the suppliers have communicated that there are additional constraints on their end, including a shortage of qualified labor. The Company also notes that their coal suppliers are "pivoting their operations towards longer-term industries and are less willing to commit assets to support short-term deliveries of coal."[9] PGE is currently estimating that the starting onsite coal inventory in 2020 will be 184,000 tons and an additional 97,500 tons will be delivered monthly through

[7] PGE/100, Niman – Kim – Batzler/18, Lines 12 through 14.
[8] PGE/100, Niman – Kim – Batzler/18, Lines 21 and 22.
[9] PGE/100, Niman – Kim – Batzler/19, Lines 17 through 20.

September 2020.[10] The 184,000 ton starting inventory will continue to be updated by PGE throughout this docket, and Staff will continue to monitor how this effects NVPC.

Q. How does PGE incorporate the supply constraints into the 2020 NVPC forecast?

A. To ensure the model does not over forecast Boardman's dispatch capabilities, PGE is modeling a maintenance deration in MONET for Q1 and Q3 that limits Boardman's dispatch to the actual amount of coal available on site. For the initial filing, this results in average derations of approximately 41.3 percent in Q1 and approximately 2.1 percent in Q3. This results in a forecasted NPVC increase of approximately $2.5 million.[11]

Q. Are there any other supply constraints?

A. Yes. Trona, a compound used to capture sulfur dioxide emissions as part of Boardman's emission control process is expected to be limited to 5000 tons in 2020. PGE's supplier, Solvay, notified the Company that Solvay had contracted their full inventory of Trona in 2020, including an allotment of 5,000 tons to PGE. The Company has updated MONET to factor in this constraint, and has modeled the full 5,000 tons of Trona to be available at the beginning of the year.[12]

Q. What is the effect to power costs of the Trona supply constraint?

A. The Trona supply constraint increases power costs by approximately $47,000.

[10] PGE/100, Niman – Kim – Batzler/19, Lines 8 through 10.
[11] PGE/100, Niman – Kim – Batzler/20, Line 13.
[12] PGE/100, Niman – Kim – Batzler/21, Lines 10 and 11.

Staff notes that while the effect is minor, this is likely only the case because of the limited coal supply at Boardman in 2020. If coal supply were not an issue, the effect on power costs could be much greater. For reference, 5.88 pounds of Trona are consumed for every MWh produced by Boardman at full load.[13] However, PGE has noted both in its testimony and in a recent technical workshop that there is still the possibility of receiving additional Trona from Solvay, or alternative Trona derivatives from other suppliers.[14] Staff will continue to monitor Trona availability and its effects to power costs throughout this proceeding.

Q. Does Staff support the way that PGE has incorporated supply constraints into the 2020 NVPC forecast?

A. Staff is generally supportive of the incorporation of supply constraints into the model. Staff does not speculate here as to whether these issues could definitely have been prevented, and will continue to monitor supply constraints and PGE's prudence in managing the Boardman shutdown. Staff has reviewed information from the Company to confirm that both suppliers have decreased coal delivery since 2013, but cannot independently verify the accuracy of supply constraint claims based on conversations.[15]

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[13] PGE/100, Niman – Kim – Batzler/20, Lines 20 through 21.
[14] PGE/100, Niman – Kim – Batzler/21, Lines 16 through 18. (PGE may be able to purchase any Trona allocated to another buyer but not purchased.)
[15] Exhibit Staff/202, Soldavini/4.

Q. Does Staff have a recommendation for this issue?

A. Staff will continue to monitor the status of the available coal inventory and the effects that this has NVPC before making a final recommendation.

Coal Inventory Management

Q. Please explain the coal inventory management issue that PGE faces in operating Boardman in 2020?

A. PGE estimates that the cost of removing coal on the ground once Boardman ceases operations at $37.50 per ton. All costs of coal removal will be categorized as decommissioning costs and collected through PGE's Schedule 145, Boardman Power Plant Decommissioning Adjustment.[16] As such, it is important to Staff that coal inventories are strategically managed, with the intent of minimizing the amount of coal left on the ground after the plant shuts down.

Q. How does the Company propose to minimize the level of coal removal?

A. PGE has included a 100 percent maintenance deration for Q4 2020, effectively assuming Boardman will shut-down on September 30, 2020. PGE states that this is done to limit the amount of coal left on site and ultimately, the coal removal costs that will be subject to collection from customers.[17]

[16] PGE/100, Niman – Kim – Batzler/22, Line 8.
[17] PGE/100, Niman – Kim – Batzler/22, Lines 6 through 8.

Q. What is the effect this modeling assumption?

A. The cost of modeling a 100 percent maintenance deration for October 2020 through December 2020 is an increase to power costs of approximately $3.6 million.[18]

Q. How does this compare to the cost of removing coal left on site after September 30?

A. PGE states that the $3.6 million increase to power costs resulting from a 100 percent deration in Q4 is “far outweighed” by the potential coal removal costs, stating that coal removal costs could reach approximately $24 million.[19] However, Staff feels this is a misleading comparator. In the next paragraph PGE reaffirms that due to supply constraints, it is not possible that enough coal could be on the ground to reach the $24 million coal removal figure.[20] In fact, assuming delivery in each of the three months in Q4 (and none of that coal being burned due to forced outages), coal removal costs could not exceed $10.97 million dollars, less than 50 percent of the Company’s stated example.[21] If PGE burned even 50 percent of this coal, removal cost for coal delivered in Q4 would fall to approximately $5.5 million. And, if PGE burned 66 percent of the coal, the removal cost for coal delivered in Q4 would fall to approximately $3.7 million, nearly identical to the effect of assuming a 100 percent Q4 deration. This leads Staff to question whether or not it makes sense to model a

[18] PGE/100, Niman – Kim – Batzler/23, Line 4.
[19] PGE/100, Niman – Kim – Batzler/23.
[20] *Ibid*.
[21] 97,500 *tons of delivered coal* * 3 *months* * $37.50 *per ton* = $10,968,750 total coal removal costs.

100 percent deration in Q4, and at the least highlights the concerns related to Trona supply constraints.

Q. Is it possible that Boardman will actually be dispatched in Q4 2020?

A. Yes. Although MONET is modeling a 100 percent maintenance deration for Boardman in Q4, if coal remains on site after September 2020, the Company will make the decision to dispatch based on economics, i.e., the plant will run if in the final quarter of 2020 if it is economic, taking into account coal disposal costs.

Q. How does PGE propose to account for any benefits if it determines Boardman is economic to run in Q4 2020?

A. The Company proposes to submit an application for deferred accounting with the Commission that would allow the Company to track any NVPC benefits accruing in the event that Boardman is economic to run in Q4. PGE's proposed methodology is to track the difference between settled Mid-C and Boardman dispatch costs (including fuel costs), with any realized value being included as an offset in the 2022 AUT (the first AUT after Q4 2020).[22]

Q. Does Staff support PGE's proposed method to track potential benefits?

A. Staff is continuing its investigation into whether or not a 100 percent maintenance deration for Q4 is a reasonable assumption. However, Staff is supportive of returning to customers any benefit that may be realized in the event that Boardman does end up being economic to dispatch in all or part of Q4 2020. Staff also supports the inclusion of said benefits as a reduction to

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[22] PGE/100, Niman – Kim – Batzler/24, Lines 9 through 14.

NVPC in the 2022 AUT, or as a reduction to Schedule 145. While Staff is supportive of some type of mechanism to track the potential benefits of economic dispatch of Boardman, the details of such an accounting application included in the Company's Opening Testimony are sparse and Staff needs additional detail on the Company's proposed deferral before it can offer full support. Staff will continue to work with the Company and other parties in this docket to determine the appropriate means to credit customers.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 359
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 25, 2019

WITNESS QUALIFICATION STATEMENT

NAME:	Sabrinna Soldavini
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Masters of Science, Agricultural Economics Purdue University, West Lafayette, Indiana Bachelor of Science, Economics University of Oregon, Eugene, Oregon
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (Commission) since August 2018 in the Energy, Rates and Finance Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues for filings made by utilities. Prior to working for the Commission I was a consulting analyst for MGT Consulting, primarily to help large public school districts prepare for bond proposals through budget analysis and statistical modelling/projections of student and demographic data. Prior to this work, I was a Research Assistant at Purdue University where I conducted research on the economic feasibility of biofuel feedstocks. Additionally, I have experience working in Data Analysis, and Program Coordination within the technology sector.

CASE: UE 359
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 25, 2019

June 6, 2019

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 018
Dated May 23, 2019

Request:

Please refer to PGE/100, Niman – Kim – Batzler/16.

a. **How far in advance does BPA provide a forecast of derations?**
b. **Please provide, in electronic spreadsheet format, the historical data PGE used to create their three-year rolling average of actual derations applied by BPA on the N-S path.**
c. **Did the Company perform any sensitivity analysis around transmission capacity deration? If so, please provide the results.**

Response:

a. The timing of the notification for derates on BPA's system is dependent largely on the circumstances and issues causing the derate. If a derate on a path is the result of a planned outage, BPA will use the processes and procedures in BPA's Outage Planning and Coordination Policy.[1] These planned outages can be in 21-day, 45-day, or even longer-term schedules and are published each month in BPA's Final Outage Plan. When these outages result in reliability limits on impacted scheduling rights, BPA has committed to post them prior to hour 22:00 of the current day for the next preschedule day in its "Scheduling Transmission Service" Business Practice.[2] In the case of forced or unplanned outages, BPA will post derates as soon as practicable.
b. Attachment 018-A provides the workbook calculating the BPA transmission capacity derates applied to the 2020 COB trading margin methodology. The workbook contains historical BPA transmission capacity data from 2016 through 2018. PGE sourced the BPA historical data from here: https://transmission.bpa.gov/Business/Operations/Paths/default.aspx

[1] https://www.bpa.gov/transmission/Reports/Documents/BPA-Outage-Policy-V60.pdf
[2] See at: https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/Scheduling-Transmission-Service-BP-V28.pdf, Section K, page 7

c. No. However, the impact of this adjustment to PGE's 2020 forecasted COB margins is small, amounting to a decrease of approximately $100,000 to a forecasted benefit of approximately $9.1 million.

UE 359

Attachment 018-A

Provided in Electronic Format Only

BPA Transmission Capacity Derates N-S Path

June 6, 2019

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 019
Dated May 23, 2019

Request:

Please refer to PGE/100, Niman – Kim – Batzler/19.

a. **Please provide any information the Company can provide to support the claim that BNSF and Union Pacific "are currently pivoting their operations toward longer-term industries and are less willing to commit assets to support short-term deliveries of coal".**
b. **When did the Company begin its efforts to increase coal deliveries?**

Response:

a. This statement is based on verbal discussions with BNSF and Union Pacific when PGE has inquired about why deliveries have been delayed and conversations with rail employees whereby PGE had learned of headcount reductions within the coal business unit. Furthermore, Attachment 019-A provides tables created using publicly available information that show declining coal transport volume by both BNSF and Union Pacific.
b. PGE began efforts to increase coal deliveries in October 2018, after the Enbridge pipeline rupture in British Columbia.

UE 359

Attachment 019-A

Provided in Electronic Format Only

BNSF and Union Pacific Coal Transport Volumes

BNSF			
Year	Coal Volume (in thousands of tons)	Total Volumes	Coal as a percentage of total volume
2018	1,902	10,698	18%
2017	1,917	10,277	19%
2016	1,803	9,758	18%
2015	2,286	10,269	22%
2014	2,270	10,275	22%
2013	2,230	10,093	22%

Source: https://www.bnsf.com/about-bnsf/financial-information/

Union Pacific			
Year	Coal Volume (tons)	Total Volumes	Coal as a percentage of total volume
2018	1,104,758	8,885,963	12%
2017	1,174,341	8,578,256	14%
2016	1,105,041	8,421,799	13%
2015	1,412,562	9,028,691	16%
2014	1,727,171	9,599,295	18%
2013	1,665,252	8,987,617	19%

Source: https://www.up.com/investor/aar-stb_reports/2015_carloadings/index.htm

June 6, 2019

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 020
Dated May 23, 2019

Request:

Please refer to PGE/100, Niman – Kim – Batzler/21.

a. **Please list the annual Trona constraint modeled in MONET, each year, from 2015 through 2020.**
b. **Why has the Company chosen to model all 5,000 tons of Trona available in January 1, 2020? Is this consistent with past NVPC filings? If not, how have Trona constraints been modeled in the past?**
c. **What are the effects of updating Monet to assume that only 1,000 tons of Trona are available beginning in January of 2020, with an additional 1,000 tons of Trona becoming available on February 1, March 1, April 1, and May 1 of 2020?**
d. **Does the Company have an update regarding the potential availability of Trona derivative from Solvay or alternative Trona derivatives? If yes, please provide any update and the affect to NVPC. If not, does the Company know the earliest date it may potentially have an update? For example, did Solvay give the Company a date by which it could expect to know if additional Trona would become available for purchase?**

Response:

a. PGE has not applied a Trona constraint in past NVPC filings.
b. PGE assumed all 5,000 tons of Trona are available January 1, 2020 to simplify the modeling. As mentioned in part a), PGE has not applied any Trona constraints in prior filings.
c. If only 1000 tons of Trona are assumed to be available in January of 2020, Boardman's availability would decrease by about 1.4% from the April 1, 2019 forecast. This is because PGE's April 1, 2019 forecast projects that 1,014 tons of Trona are needed in January 2020. Therefore, 14 tons of Trona would need to be moved and consumed in another month. If 1000 tons of Trona are assumed to be available in each month from February through May 2020, Boardman's availability would not be impacted.

d. PGE currently has commitment from Solvay to supply 5,000 tons of Trona and 4,800 tons of Sodium Bicarbonate (equivalent to 3,000 tons of Trona) to support 2020 operations at Boardman. Solvay will reassess its Trona availability during Q3 2019 and then inform PGE if they can ship more Trona, instead of Sodium Bicarbonate, in 2020. While Sodium Bicarbonate is a reasonable substitute for Trona, it costs approximately 50% more than Trona per ton, and transportation costs would increase by 75 truckloads. (3,000 vs. 4,800 tons @ 24 tons per truck).

June 6, 2019

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 021
Dated May 23, 2019

Request:

Please refer to PGE/100, Niman – Kim – Batzler/21. Referring to the statement "If the plant was unavailable due to an unplanned outage, or for any other reason it would cost approximately $24.0 million, or approximately $37.50 per ton, to remove the remaining coal from the site…" please provide any information/evidence the Company used to arrive at the $24.0 million estimate.

Response:

Please refer to PGE's April 1 initial filing, "Output" folder, step 0c, workbook "#M610PUC10-00c-2020 AUT output".

If PGE was not modeling a 100% Boardman deration for Q4 of 2020, the plant would be forecast to generate approximately 951,140 MWh in Q4 2020. PGE's $24.0 million coal removal cost estimation is based on the assumption that 0.66 tons of coal is needed to generate 1 MWh of energy. That is, as mentioned in PGE Exhibit 100, page 23, lines 8-10, modeling Boardman to run in Q4 of 2020, PGE would have to purchase and nominate transportation for approximately 632,000 tons (951,140 MWh*0.66 tons/MWh).

If Boardman became unavailable, at a $37.50 coal removal cost per ton it would cost approximately $24.0 million to remove the 632,000 tons of coal needed to run Boardman in Q4 of 2020.

CASE: UE 359
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

June 25, 2019

June 19, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Jay Tinker
Director, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to AWEC Data Request No. 032
Dated June 5, 2019

Request:

Please refer to PGE/100, Kiman-Kim-Batzler/15 [SIC], lines 1 to 8.

a. **Does the UE 335 method of calculating COB margins rely on historic transaction volumes?**
b. **If the response to subpart a is yes, please explain why the deration proposal does not double count the impact of derations**.

Response:

a. Yes, the method of calculating COB trading margins relies on PGE's historic COB market transaction volumes from 2016 to 2018.

b. PGE's N-S capacity on the California-Oregon Intertie (COI) transmission path is 296 MW of the total transfer capacity (TTC) of 4800 MW. On multiple occasions from 2016 to 2018 PGE's share of the COI's available transfer capacity (ATC) as determined by BPA was lower than PGE's actual used capacity. This means that PGE had to purchase short-term transmission rights for the opportunity to trade between the Mid-C and the COB power hubs. The costs of purchasing this additional transmission are not modeled in PGE's NVPC, but are reflected in actual NVPC even though, we are adjusting our NVPC forecast to reflect an estimated benefit to customers for transacting between the two energy markets. The transmission derate proposal in the COB margin calculation method aims at partially recognizing the costs that PGE incurs when purchasing short-term transmission capacity on BPA's N-S transmission path.

June 19, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Jay Tinker
Director, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to AWEC Data Request No. 031
Dated June 5, 2019

Request:

Please refer to PGE/100, Kiman-Kim-Batzler/14 [SIC], lines 12 to 14.

a. **Please provide all workpapers and communications related to the continued investigation of granularity and improved modeling of COB margins.**
b. **Please provide PGE's conclusions related to this investigation and explain how PGE arrived at these conclusions**.

Response:

PGE is objecting to this request on the basis that it is overly broad and unduly burdensome. Subject and without waiving this objection PGE replies as follow:

a. Attachment 031-A provides work papers and communication related to PGE's investigation into increasing the granularity to improve the modeling of COB margins.
b. PGE concluded that increasing the granularity to an hourly / weekly forecast would be overly burdensome, prone to errors, and does not provide a significant improvement, if any, to the modeling of COB trading margins. As such PGE continued to use the COB trading margin method from its 2019 general rate case (UE 335).

Attachment 031-A is protected information subject to Protective Order No. 19-112.

UE 359

Attachment 031-A

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

COB Trading Margin Method Investigation
PGE Communication and Work Papers

CASE: UE 359
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

June 25, 2019

Q. Please state your name, occupation, and business address.

A. My name is Moya Enright. I am a Senior Utility and Energy Analyst employed in the Energy, Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. I discuss Portland General Electric Company's 2020 Automatic Update Tariff (AUT) filing and Staff's analysis and recommended Commission action regarding the Western Energy Imbalance Market (EIM) benefit forecast and forecasted cost of wholesale transactions.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

- Staff/301: Witness Qualification Statement.
- Staff/302: PGE's Responses to DR Nos. 23, 31, 32, 38.
- Staff/303: PGE's attachment to Confidential Response to DR No. 34.
- Staff/304: PGE's 2018 Annual Report, pages 16 & 17.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. WESTERN ENERGY IMBALANCE MARKET

Q. What is the Energy Imbalance Market?

A. The Energy Imbalance Market (EIM) is a real-time wholesale power market. Its automated dispatch system provides economic benefits to participants by efficiently balancing load and generation resources. It also provides reliability and renewable integration benefits to the grid. PGE joined the EIM in October 2017.

Q. How does participating in the EIM benefit PGE?

A. PGE can benefit from its participation in EIM in a number of ways:

- *Sub-Hourly Dispatch Benefits*. These benefits arise due to EIM facilitating transactions between PGE, CAISO, and other EIM participants on a five- and 15-minute basis. They can be further broken down into two categories:
  - *Dispatch Benefits from EIM Transfers*. These benefits arise when PGE imports from EIM at a lower price than its marginal production costs, or when PGE exports to the market at a profit.
  - *Dispatch Benefits from Excess Reserves*. PGE is required to start each hour with sufficient resources and ramping capacity to serve its customers; however within the hour, the diversified footprint of EIM allows PGE to hold lower reserves than would otherwise be necessary. Reserves that are freed up within the hour can dispatched in the market, increasing the Company’s realized Sub-Hourly Dispatch Benefits.

- *Greenhouse Gas (GHG) Revenue*. GHG revenue is awarded when CAISO determines generation within an EIM entity served CAISO load. This mechanism is intended to compensate entities importing power into California for their compliance costs. In the case of EIM entities without GHG compliance costs, this revenue stream creates a financial benefit.

Q. How has the EIM changed since PGE's entrance?

A. PGE began participating in the EIM in October 2017. Since that date, both Idaho Power and Powerex[1] have joined the EIM. Two new entities are expected to join the EIM in 2020.[2] New participants in the EIM increase competition and interconnection, and contribute to the ramping diversity benefit.

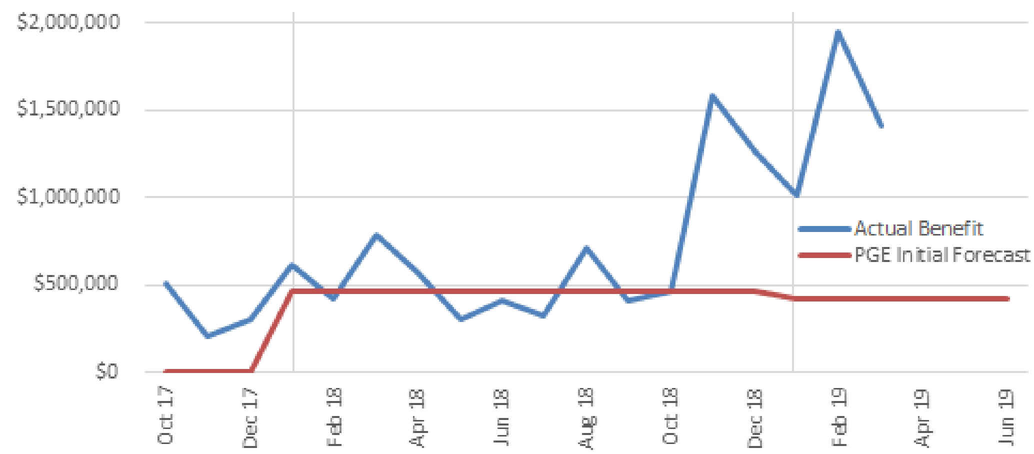
As detailed by PGE in testimony, market changes introduced in late 2018 have changed the system for GHG awards.[3] The effects of this change will be discussed further in Staff's testimony.

Q. Please give an overview of forecasted EIM benefits and actual EIM benefits to date.

A. Figure 1 below shows PGE's initial forecast of EIM benefits from the last three filings, tracked against the benefits that were actually realized in those years.

[1] Powerex is an energy marketing and trading company based in Vancouver, Canada. It is a subsidiary of BC Hydro, Canada's third largest electric utility.
[2] These entities are Salt River Project, one of Arizona's largest utilities; and Seattle City Light.
[3] PGE/100, Niman-Kim-Batzler/13.

Figure 1



[4]

It is worth noting that GHG revenues have not been included in previous forecasts of EIM benefits. This is in spite of the Company's monthly GHG revenue averaging $143,156 ($1.7 million over 12 months) since joining EIM. Figure 2 shows PGE's initial benefit forecast, adjustments to the forecast, and actual benefits in table form for ease of comparison.

It is evident from both Figure 1 and Figure 2 that there has been a significant increase in EIM benefits in the six months ending March 2019. This may be due in part to a new EIM participant "learning curve", as hypothesized in UE 323,[5] and corroborated by PacifiCorp in UE 339,[6] or it may be a structural shift in EIM benefits. With the limited data available however, it is difficult to conclude whether this trend will continue.

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[4] UE 308/PGE/400, Niman-Peschka-Hager/20; UE 319/PGE/300, Niman-Peschka-Rodehorst/9; UE 335/PGE/300, Niman-Kim-Batzler/13; Staff/302, Enright/1 (PGE's response to Staff DR 23, attachment A).
[5] UE 323/Staff/400, Gibbens/7.
[6] UE 339/PAC/100, Wilding/7.

Figure 2

	Forecasted Benefit (Initial Filing)	Actual Benefit	Adjustment (per Final Order)
2017	$0	$1	Cost and Benefits set to zero out
2018	$5.6	$7.9	$0.5 increase
2019	$5	$4.4†	$4.5 increase*
2020	$6.6		

† *January to March only ($17.6 million when annualized)*

* *Included four issues settled for total dollar adjustment* [7]

Q. Has PGE proposed to change its methodology for forecasting EIM benefits?

A. Yes. In the 2019 AUT, PGE's inter-regional dispatch benefits were forecasted by a consultancy firm. For the 2020 AUT PGE proposes to model these benefits in-house.

As mentioned previously, GHG revenues were not included in previous forecasts of EIM benefits. 2020 is the first year in which PGE has proposed to include GHG revenues in its EIM benefits forecast. PGE also proposes using an in-house forecast for this EIM benefit.

In the upcoming testimony Staff analysis of the forecasts for each benefit type will be discussed separately.

[7] UE 308/PGE/400, Niman-Peschka-Hager/20; UE 319/PGE/300, Niman-Peschka-Rodehorst/9; UE 335/PGE/300, Niman-Kim-Batzler/13; Staff/302, Enright/1 (PGE's response to Staff DR 23, Attachment A).

Q. Explain how sub-hourly dispatch savings are modeled in the 2020 AUT.

A. PGE has proposed using its actual sub-hourly dispatch savings from 2018, adjusted for inflation, as a forecast for 2020 EIM benefits. PGE received $6.3 million in sub-hourly dispatch benefits in 2018. Once adjusted for inflation at a rate of 2.5 percent, this results in a forecasted saving of $6.6 million in the 2020 AUT.

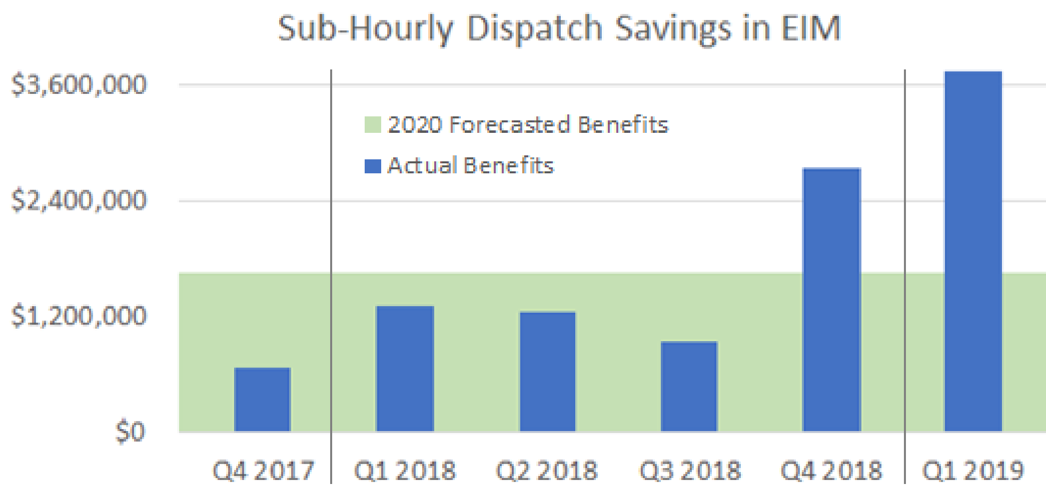
Q. Does Staff have any concerns with the sub-hourly dispatch savings model proposed by PGE?

A. Yes. Staff discovery has shown that in recent months PGE's sub-hourly dispatch benefits have increased markedly, to a total of $6.5 million over six months.[8] This contrasts sharply with the $2 million total benefit received in the same six months of the prior year, and constitutes more than a threefold increase in benefits.

This data is represented graphically in Figure 3, which shows actual quarterly sub-hourly dispatch benefits compared with PGE's sub-hourly dispatch benefit forecast for 2020.

[8] October 2018 to March 2019. Staff/302, Enright/1 (PGE's Response to Staff DR 23, attachment A).

Figure 3



The data clearly shows that EIM benefits are increasing. This is logical given the expanding footprint of EIM and PGE's increasing familiarity with the market; however increasing benefits are not accounted for in PGE's proposed model.

Staff is not satisfied with PGE's 2020 forecast of $6.6 million for sub-hourly dispatch benefits. It is clearly an unrealistic forecast, given that in the latest six months actual benefits have totaled $6.5 million. The six month total comes close to surpassing PGE's forecast for the entire 12 months of 2020.

Q. Explain how GHG revenues are forecasted in the 2020 AUT.

A. PGE has argued that market changes in late 2018 reduced its monthly benefits from GHG awards by between 20 and 48 percent.[9]

On the basis of this change, PGE proposes to reduce actual GHG revenue by 50 percent to establish a baseline for its GHG model. PGE then adjusts the

[9] PGE/100, Niman-Kim-Batzler/13, table 2.

baseline to account for inflation and an increasing floor price for GHG allowances, to arrive at a forecasted GHG benefits figure.

PGE received $1.6 million GHG revenue in 2018, and it has forecasted a benefit of $0.9 million GHG revenue in the 2020 AUT.

Q. Does Staff have any concerns with the GHG revenue model proposed by PGE?

A. Yes, Staff has serious concerns with this model.

PGE has explained that market changes in late 2018 had the effect of reducing its GHG awards,[10] and argues that this change justifies a 50 percent reduction in the GHG revenue forecast for 2020.

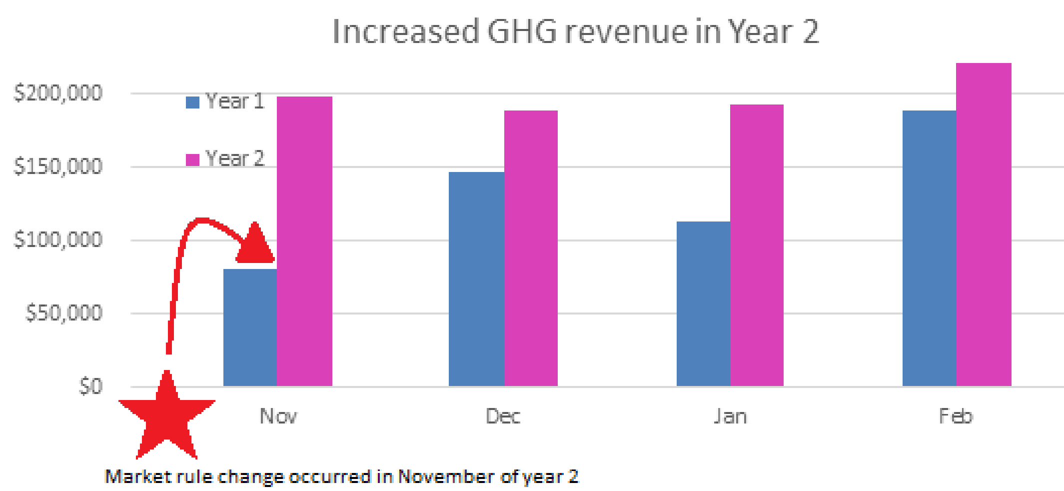
Staff analysis has shown this adjustment to be irrational and not reflective of the actual GHG revenue that PGE is receiving from EIM. Staff is strongly against using this model for the following reasons:

- *GHG Awards do not equal GHG Revenue.* In its testimony, PGE has provided a table summarizing GHG awards during four months of their first and second years participating in EIM (November to February in each year), illustrating how GHG awards have declined since the market rule change. What is not made clear to the reader is that GHG *awards*, measured in MWh, do not equal GHG *revenue*, a dollar value. Staff discovery has shown that despite GHG awards declining by 43 percent in the four months following the change, PGE's GHG revenue *increased* by 52 percent.[11]

[10] PGE/100, Niman-Kim-Batzler/12.
[11] Staff/302, Enright/1 (PGE's response to Staff DR 23, Attachment A).

Expressed in dollar amounts, GHG revenue for the four months in year one totaled $503,441, increasing to $803,853 in the same months of year two. In short, PGE's GHG revenue *increased* after the market rules change. This is illustrated in Figure 4.

Figure 4



- *50 percent adjustment is in excess of the trend.* PGE has provided a summary of GHG awards for the months November to February of years one and two.[12]

The Company argues that the reduction in GHG awards justifies a 50 percent reduction in forecasted GHG revenues, however PGE does not show the actual change in GHG awards to give context to their proposal. In order to assist the reader in drawing valuable comparisons, Staff has provided an updated table in Figure 5 below, which includes actual the percentage difference in awards.

[12] PGE/100, Niman-Kim-Batzler/13, table 2.

This table shows that GHG awards fell by 43 percent on average during the four-month period. This is substantially lower than the 50 percent adjustment proposed by the Company.

Figure 5

	Year 1	Year 2	% of Year 2 versus Year 1	% difference
November	37,488 MW	30,715 MW	82%	- 20%
December	54,649 MW	28,352 MW	52%	- 48%
January	53,294 MW	30,389 MW	57%	- 43%
February	53,868 MW	25,236 MW	47%	- 47%
Average (Nov – Feb)	49,825 MW	28,673 MW	58%	- 42%
Average (Dec – Feb)	53,937 MW	27,993 MW	52%	- 48%
Average reduction				- 43%
Proposed reduction				- 50%

In addition to PGE's proposed approach misleadingly equating GHG awards to GHG revenue, and overstating the reduction in awards, Staff is also concerned that the approach uses too little data. PGE's initial filing presents 16 months of data, but only the last four of these months show a decline. PGE has not presented sufficient evidence to prove that the recent trend will continue, and similarly, the limited dataset makes it difficult to conclude that there will be an enduring change.

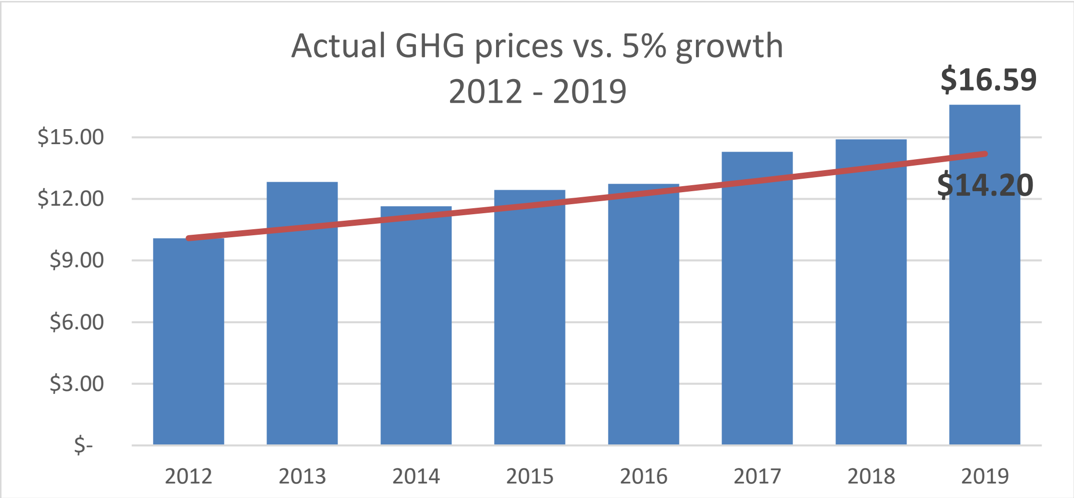
- *Actual GHG price increases far exceed the proposed five percent inflator.*

PGE has proposed to increase GHG revenues by seven and a half percent each year. This includes inflation of two and a half percent, and an expected increase in GHG prices of five percent per year. It argues that five percent is consistent with the increase in GHG allowance floor prices permitted by

California Air Resource Board (CARB),[13] however one must take into account that a *floor* price does not reflect a *market* price.

Staff discovery has shown that actual increases to GHG allowance prices exceed the 5 percent increase on *floor* prices permitted by CARB. In fact, the average price of GHG allowances auctioned to date in 2019 is 16 percent higher than in 2017 when PGE joined EIM. Price growth in GHG allowances prices in shown in Figure 6.

Figure 6



This example serves to illustrate that current growth in GHG allowance prices exceeds the 5 percent suggested by PGE. Nevertheless, both measures are proxies for growth in GHG revenue per MWh in EIM.

Staff has used data provided by PGE to estimate that GHG awards had a dollar value of $2.62 per MWh during the sampled four months of year one, and a dollar value of $7.08 per MWh during the sampled four months of year

[13] PGE/100, Niman-Kim-Batzler/14.

two.[14, 15] Staff believes that further discovery is warranted to shed light on how this per MWh price is arrived at in EIM. Consequently, Staff discovery regarding this sub-issue is ongoing.

Q. What are Staff's recommendations regarding the forecasting of EIM benefits in the 2020 AUT?

A. Staff recommends a similar approach to the model proposed by PGE, with some crucial adjustments:

- *Update model with latest available data.* In light of the recent step change in both sub-hourly dispatch benefits and GHG revenues, Staff recommends using the most recent 12 months of EIM benefit data to establish a baseline, rather than the 2018 calendar year figures proposed by PGE.

  To achieve this, the forecast should be updated with new data in July, October and November. This would constitute a change from the standard filing updates, as EIM benefits are not scheduled to be updated even once, per the current AUT process. Staff expects that a dataset including actual September 2019 results can be included in the November update.[16]

  Staff believes that this approach is essential to ensure that either an ongoing upward trend, or a reversal of the uptick seen in the past six months, is accounted for in the final forecast.

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[14] Staff has calculated dollar per MWh GHG revenue as average GHG revenue in the period divided by average GHG awards in the period.

[15] PGE/100, Niman-Kim-Batzler/13, table 2; and Staff/302, Enright/1 (PGE's response to Staff DR 23, attachment A).

[16] This estimate is based on March 2019 data being available in May 2019, per Staff/302, Enright/1 (PGE's response to Staff DR 23, attachment A).

Furthermore, Staff has noted that in April, May and June 2018, GHG revenues were very low, measuring just five to 11 percent of the 2018 monthly average. Staff is keen to ensure that this is picked up by the model if it repeats in 2019.

- *Adjust actual EIM benefits using an escalation factor.* Staff recommends that the baseline for EIM benefits is adjusted by an escalation factor to reflect likely 2020 EIM benefits. Staff proposes a different escalation factor for each EIM benefit type:
    - *GHG revenue escalation factor.* Staff recommends an escalation factor including inflation at a rate of two and a half percent, and GHG allowance price increase of 11 percent.[17]
    - *Sub-Hourly Dispatch savings escalation factor.* Staff recommends an escalation factor including inflation at a rate of two and a half percent. If once further data becomes available, the recent uptick in EIM benefits is found to continue, it would be prudent for Staff to recommend a further addition to the escalation factor to reflect this.

Q. Would Staff advocate for this forecasting method to be used in coming years?

A. No. Going forward, Staff would advocate for the use of a trend line to forecast EIM benefits, with time as the explanatory variable. This approach is preferable as it takes more than twelve months of data into account, allowing

[17] Average GHG allowance prices at auction in 2019 are 11 percent higher than in 2018.

increasing benefits to PGE and consumers from EIM participation to be reflected.

Furthermore, this approach would be consistent with the EIM benefits forecast agreed on for PacifiCorp's 2019 TAM filing.[18] Its use would be a positive step toward standardizing the EIM benefits forecasting methodology used by Oregon's IOUs.

In the case of the 2020 AUT, Staff finds it more appropriate that the forecasting model recommended above (on page 13) is used. The reasons for this is PGE is still relatively new to the EIM, with less than two years of historic EIM benefit data. Such a small dataset is not sufficient for a robust trend line to be produced.

[18] UE 339, Stipulating Parties/100, Wilding, Gibbens, Jenks, Mullins, Higgins/20.

ISSUE 2. WHOLESALE TRANSACTIONS

Q. Please provide an overview of wholesale purchase costs and sales revenue in the 2020 AUT, compared with the 2019 AUT.

A. PGE forecasts power market purchases will increase NVPC by $41.3 million in 2020.[19] This increase is made up of a $30.4 million increase due to higher market forward power prices, and a $10.9 million increase due to an expected load increase in 2020.[20]

Overall, a $22.53 per MWh power cost is forecasted for 2020. This represents a 15 percent increase on 2019 per MWh costs of $19.60.[21] This forecast is subject to change as a result of updates to natural gas and power prices later in the AUT process.

Q. Please describe Staff's analysis of wholesale purchase costs and sales revenues.

A. PGE models NVPC using Monet, a production cost model that simulates the dispatch of the Company's power system on an hourly basis. The model economically dispatches plant and makes market purchases and sales in a manner that achieves the lowest possible power cost. Staff has found no issues in the data or methodology.

[19] PGE/100, Niman-Kim-Batzler/33.
[20] PGE/100, Niman-Kim-Batzler/34.
[21] PGE/100, Niman-Kim-Batzler/33.

Q. Does Staff have any concerns with PGE's forecasted wholesale transactions?

A. PGE has indicated that price spikes in power and natural gas markets over the past two years have had the effect of increasing forward prices in the region. This was identified in testimony by PGE as a driver of higher market purchase costs forecasted for 2020.[22] The inflationary effect of spot market volatility on the forward prices used in this filing was also discussed in a pre-filing workshop with Staff, which occurred in the weeks following the March 2019 price spikes in power markets.

The current AUT procedure calls for gas and electric forward curves to be updated in Monet in July, October and November, with the final November update being used to determine 2020 power costs.

Staff is concerned about the potential for volatility in energy markets on dates surrounding the final update to inflate final power costs. Staff has raised this issue with PGE, who responded as follows:

> *PGE continually reviews its NVPC modeling for improvements and refinements in response to any number of internal and/or external changes that may affect power costs. Regarding the recent volatility experienced in the Northwest power markets, PGE has taken notice and is currently determining: 1) whether these*

[22] PGE/100, Niman_Kim_Batzler/33.

> *recent events signal a long-term shift in markets, and 2) what, if any, changes are needed to address this potential shift.*[23]

Staff recommends that this subject be analyzed by the Company prior to the end of the current AUT process. Staff recommends that the Company provide details of their analysis and any changes deemed appropriate in testimony prior to the end of this filing.

Q. Does PGE hedge its future energy requirements?

A. Yes. PGE's hedging policy sets out to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[24]

In the case of wholesale power purchases, the Company uses short- and long-term wholesale purchase agreements to hedge future requirements. The contracts have terms ranging from one month to 37 years, and are made up of seasonal peaking capacity, several hydro purchase agreements, and other contracts.[25]

Q. There has been significant volatility in Northwestern energy markets over the past twelve months, with spiking electricity prices, the Enbridge gas pipeline forced outage, and the declaration of bankruptcy by PG&E in January 2019. How has this affected PGE?

[23] Staff/302, Enright/2 (PGE's response to Staff DR 31).
[24] Staff/303, Enright/1 (PGE's response to Staff DR 34, confidential attachment 34-A).
[25] Staff/304, Enright/1 & 2 (PGE's 2018 Annual Report, pages 16 & 17).

A. In response to Staff discovery, PGE reviewed its energy portfolio and asserted that it has no contracts with PG&E, and is not aware of any exposure to PG&E.[26]

When queried about the issue of recent market volatility and the Company's energy risk management policy, PGE asserted that its risk management policy is designed to function regardless of market volatility.[27]

While natural gas prices were higher in 2019 due to the Enbridge pipeline operating at a reduced capacity, the forced outage was an unexpected event. The effects of the forced outage or other market volatility on power costs will be assessed in future Power Cost Variance Mechanism filings.

Q. Does Staff have a recommendation regarding this issue?

Yes. Staff recommends that the effects of market price volatility on forward price curve formation be analyzed by the Company prior to the end of the current AUT process. Staff recommends that the Company provide details of their analysis and any changes deemed appropriate, in testimony prior to the end of this filing.

Q. Does this conclude your opening testimony?

A. Yes.

[26] Staff/302, Enright/3 (PGE's response to Staff DR 32).
[27] Staff/302, Enright/4 (PGE's response to Staff DR 38).

CASE: UE 359
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 25, 2019

WITNESS QUALIFICATIONS STATEMENT

NAME:	Moya Enright
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility and Energy Analyst Energy Rates, Finance and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Energy Risk Professional Certification (part-qualified). Global Association of Risk Professionals. M.Sc. Political Science, 2015. University of Amsterdam. M.Sc. Investment, Treasury and Banking, 2011. Dublin City University. B.A. International Business and Languages, 2008. Dublin City University through a joint curriculum with École Supérieure de Commerce de Montpellier.
EXPERIENCE:	Senior Utility and Energy Analyst at OPUC since January 2019. Energy Trader for Meridian Energy from 2015 to 2019. Meridian Energy is a power generator and retailer operating both in New Zealand and Australia. Trading and Operations Analyst at Tynagh Energy from 2011 to 2013. Tynagh Energy is an independent power producer operating in the Republic of Ireland. Senior Electricity Market Controller at EirGrid from 2008 to 2011. EirGrid is the Irish electricity Transmission System Operator. It operates the Single Electricity Market for the Republic of Ireland and Northern Ireland. Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG in Northern Ireland.

	Year	2017					
	Month	Oct	Nov	Dec	Jan	Feb	Mar
1	Sub-Hourly Dispatch Savings	$386,211	$125,509	$157,444	$501,125	$230,898	$581,337
2	Hydro GHG Revenue	$120,273	$80,556	$147,559	$112,904	$189,422	$201,533
3	CAISO Grid Management Charges	($64,322)	($60,285)	($75,408)	($67,374)	($64,183)	($73,295)

	Year	2017	2018	2019
1	Sub-Hourly Dispatch Savings	$669,163	$6,256,892	$3,751,607
2	Hydro GHG Revenue	$348,388	$1,609,509	$618,911
3	CAISO Grid Management Charges	($200,015)	($883,470)	($238,203)
		$817,537	$6,982,931	$4,132,315

2018								
Apr	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
$564,074	$300,062	$391,671	$161,673	$515,363	$263,494	$284,034	$1,388,981	$1,074,179
$7,509	$6,105	$14,691	$162,685	$193,815	$148,559	$184,289	$198,597	$189,400
($58,066)	($50,957)	($64,548)	($86,624)	($96,028)	($79,384)	($79,316)	($88,887)	($74,808)

2019		
Jan	Feb	Mar
$818,894	$1,721,656	$1,211,058
$193,742	$222,114	$203,055
($75,896)	($82,954)	($79,353)

CASE: UE 359
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 25, 2019

June 7, 2019

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jay Tinker
Director, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 023
Dated May 24, 2019

Request:

See PGE/100, Niman-Kim-Batzler/10, table 1. Please provide a copy of this table in Excel format with the following edits:

a. **Data shown on a monthly basis, for every month since PGE joined EIM until present.**
b. **Show savings arising from lower flexible ramping requirements and savings arising from PGE's ability to export and import in near real-time separately.**
c. **If the sum of the two values requested in question 2c does not equal the value of sub-hourly dispatch savings, please explain.**

Response:

a. Attachment 023-A provides sub-hourly dispatch savings, Hydro GHG revenues, and CAISO grid management charges for the period between October 2017 and March 2019.

b. PGE's measurement of *actual* benefits does not differentiate between 'dispatch benefits' and 'flexible reserve savings.' There is no need to differentiate between the two categories, because PGE's 'biddable' resources are also the resources that predominantly hold PGE's flexible reserves prior to participation in the EIM each hour. Therefore, the sub-hourly market instructions issued by CAISO in the EIM reflect the optimization of PGE's sub-hourly dispatch alongside other EIM entities, including the economic use of flexible reserves needed to meet the EIM requirements.

c. Please see PGE's response to part b).

UE 359

Attachment 023-A

Provided in Electronic Format Only

PGE Sub-hourly dispatch savings, Hydro GHG revenues, and CAISO grid management charges
October 2017 – March 2019

June 7, 2019

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jay Tinker
Director, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 031
Dated May 24, 2019

Request:

If PGE has considered making changes to its annual power cost update methodology in light of the recent volatility in Northwest energy markets, please provide a full account of this.

Response:

PGE continually reviews its NVPC modeling for improvements and refinements in response to any number of internal and/or external changes that may affect power costs. Regarding the recent volatility experienced in the Northwest power markets, PGE has taken notice and is currently determining: 1) whether these recent events signal a long-term shift in markets, and 2) what, if any, changes are needed to address this potential shift.

June 7, 2019

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jay Tinker
Director, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 032
Dated May 24, 2019

Request:

PG&E filed for Chapter 11 bankruptcy protection in January 2019.

a. **Please detail PGE's exposure to this event.**

b. **If PGE's power cost filing was affected by the event, please quantify any financial impacts, and provide a narrative explanation of non-financial impacts.**

c. **If PGE has carried out analysis relating to this event, please provide the analysis.**

Response:

a. PGE has no energy contracts with PG&E and is not aware of any exposure to PG&E.

b. PGE is not aware of any impacts. PG&E continues to operate and the general wholesale energy trading market does not appear to be impacted.

c. PGE reviewed its energy portfolio and confirmed that there were no contracts with PG&E.

June 7, 2019

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jay Tinker
Director, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 038
Dated May 24, 2019

Request:

If PGE has considered making changes to its energy risk management policy in light of the recent volatility in Northwest energy markets, please provide a full account of this.

Response:

PGE's risk management policy is designed to support the procurement and delivery of safe, affordable and reliable energy to our customers regardless of market volatility. As such, no changes have been necessary due to recent market volatility.

CASE: UE 359
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 303

Exhibits in Support Of Opening Testimony

June 25, 2019

STAFF EXHIBIT 303

IS CONFIDENTIAL

CASE: UE 359
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

June 25, 2019

PGE owns 79.5%, and is the operator of record, of the Kelso-Beaver Pipeline, which directly connects PW1, PW2, and Beaver to Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the Kelso-Beaver Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 103,305 Dth per day of firm natural gas transportation capacity to serve the three plants.

PGE also has contractual access to natural gas storage in Mist, Oregon from which it can draw as needed. The Company expects to utilize this resource when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility is owned and operated by a local natural gas company, NW Natural, and may be utilized to provide fuel to PW1, PW2, and Beaver.

PGE has entered into a long-term agreement with NW Natural to expand the current storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-mile pipeline, that will be designed to provide no-notice storage services to these PGE generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which NW Natural estimates will be completed during the Spring of 2019, at a cost of approximately $144 million.

Beaver has the capability to operate on fuel oil when it is economical or if the plant's natural gas supply is interrupted. PGE had an approximate four-day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2018. The current operating permit for Beaver limits the number of gallons of fuel oil that can be burned daily, which effectively limits the daily hours of operation of Beaver on fuel oil.

To serve Coyote Springs and Carty, PGE has access to 119,500 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. PGE believes that sufficient market supplies of natural gas are available for Coyote Springs and Carty for the foreseeable future, based on anticipated operation of the plants. Although Coyote Springs was designed to also operate on fuel oil, such capability has been deactivated in order to optimize natural gas operations.

Coal PGE has purchase agreements that, together with existing inventory, will provide coal sufficient for the anticipated operating needs for Boardman during 2019. The coal is obtained from surface mining operations in Wyoming and is delivered by rail under two separate transportation contracts which extend through 2020.

The terms of contracts and the quality of coal are expected to be staged in alignment with required emissions limits. PGE believes that sufficient supplies of coal are available to meet anticipated coal-fired operations of Boardman through 2020.

The Colstrip co-owners currently obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The company that owns and operates the mine declared bankruptcy in the fourth quarter of 2018. Debtors in the bankruptcy proceeding filed notice on January 19, 2019 of their decision to reject the co-owners' current coal contract, which currently extends through December 31, 2019. The co-owners have filed objections to such a plan, and a hearing on the debtor's plan is expected to be held by March 1, 2019. In the event the current coal supply contract is ultimately rejected in bankruptcy, Colstrip and the co-owners may have a material limitation on coal supply for a portion of 2019, and beyond, which may result in increased replacement power costs.

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis. Such contracts have original terms ranging from one month to 37 years and expire at varying dates through 2055.

PGE's medium-term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel.

The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

Capacity/exchange—PGE has one contract that provides the Company with firm capacity to help meet peak loads. The agreement allows for up to 100 MW of seasonal peaking capacity during winter periods through February 2019. A new seasonal peaking capacity agreement during the summer and winter periods for 100 MW will begin in July 2019 and continue through February 2024. An additional 200 MW of annual capacity will be added in January 2021, with a five-year term.

Hydro—During 2018, the Company had the following agreements:

- *Mid-Columbia hydro*—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington for a portion of the output of two hydroelectric projects on the mid-Columbia River. One contract representing 159 MW of capacity that expires in 2028 and one contract representing 163 MW of capacity that expires in 2052. Although the projects currently provide a total of 322 MW of capacity, actual energy received is dependent upon river flows and capacity amounts may decline over time.
- *Confederated Tribes*—PGE has a long-term agreement under which the Company purchases, at index prices, the Tribes' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 159 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. In 2014, PGE entered into an agreement with the Tribes under which the Tribes have agreed to sell, on modified payment terms, their share of the energy generated from the Pelton/Round Butte hydroelectric project exclusively to the Company through 2024.
- *Other*— PGE has two contracts that provide for the purchase of power generated from hydroelectric projects with an aggregate capacity of 37 MW and contract expiration in 2032.

Wind—PGE has three contracts that provide for the purchase of renewable wind-generated electricity and extend to various dates between 2028 and 2035. The expected energy from these wind contracts differs from the nameplate capacity and is expected to approximate 39 MWa, dependent upon wind conditions.

Solar—PGE has fifteen agreements that expire throughout 2031 to 2037 to purchase power generated from photovoltaic solar projects, which have a combined generating capacity of 40 MW. In addition, the Company operates, and purchases power from two solar projects with an aggregate of approximately 6 MW of capacity. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions.

Other—These primarily consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities and Qualifying Facilities under the Public Utilities Regulatory Policies Act (QF), over terms extending into 2032.

Short-term contracts—These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Company's load requirements.

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 400

Opening Testimony

June 25, 2019

Q. Please state your name, occupation, and business address.

A. My name is Kathy Zarate. I am a Utility Economist employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize Staff's analysis and recommendations on certain issues regarding Portland General Electric (PGE)'s 2020 Annual Update Tariff (AUT) filing, Docket No. UE 359.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Staff/401: Witness Qualification Statement
- Staff/402: PGE's Responses to Staff Data Request Nos. 008, 011,013, and 016.
- Staff/403: PGE's Confidential Responses to Staff Data Request Nos. 001,004,009, and 017.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. QUALIFYING FACILITIES

Q. Please discuss QFs and how the costs are projected by PGE for the 2020 test year.

A. As part of PGE's projection of QF costs, PGE identifies and develops a forecast of the cost of purchasing power from QFs projected to come on line in 2019 and 2020. PGE's Response to Staff Data Request No. 001, a copy of which is attached as Exhibit Staff/403, provides a breakdown of QF purchases under Schedules 201 and 202. The total costs of purchases from new QFs for the 2020 test year is **[Begin Confidential]** [redacted] **[End Confidential]**.[1]

Q. What has been the recent experience by PGE in the level of forecasted new QF purchased power costs as compared to actual purchased power costs?

A. In comparing PGE's forecasted costs to actuals, there is a large difference in actuals as compared to forecasts with PGE actuals averaging only **[Begin Confidential]** [redacted] **[End Confidential]** of PGE's forecasted levels.

Table 1[2]

[Begin Confidential]

Years	2015	2016	2017	2018	Total
Projected QFs Power Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Actual new QF's Power costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] The source for these numbers is PGE's responses to Staff Data Request DR 1, Attachment A, cell BI 164 and Attachment B Conf. cell BI 12.
[2] The source for these numbers is PGE's response to Staff Data Request DR 4, Attachment A. Confidential Tab "QFs Actual vs Projected '15-'18".

% Actual vs Projected	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[End Confidential]

Q. Has the issue of accuracy of forecasts of QF power costs appeared in prior PGE power cost filings?

A. Yes. In Order No. 18-405 in Docket No. UE 335, the Commission adopted a stipulation under which PGE tracked and trued up the difference in costs stemming from differences in projected versus actual QF commercial operation dates (CODs). This tracking and true-up was independent of the annual true-up in the Power Cost Adjustment Mechanism applied to all other power costs. Differences in projected versus actual CODs is one reason the projections of purchased power costs from new QFs would differ from actual.

Q. Is there another reason as to why projected versus actual new QF purchased power cost might differ?

A. Yes, another reason why actual versus projected new QF purchased power costs might differ is that the level of actual MWH production from the new QFs could differ from the projected amount.

Q. Does PGE also replace projected with actual MWH production from new QFs?

A. No. Staff Data Request No. 8, a copy of which is attached as Exhibit Staff/402, posed that question to PGE. PGE responded that, "to perform a true up for QF projected generation versus actual generation would be overly burdensome."[3]

Q. Assuming PGE continues to over-forecast the power purchased from new QFs, what could that mean for 2020?

A. As noted above, for the period 2015-2018, actual new QF purchased power costs has averaged **[Begin Confidential]** [redacted] **[End Confidential]** of PGE's projection. If PGE were to use this percent factor it would translate to a projection of QF costs of [**Begin Confidential]** [redacted] **[End Confidential]** less than what PGE projected in its initial filing.

Q. Do you recommend an adjustment of [Begin Confidential] [redacted] **[End Confidential] to PGE's projection of purchased power cost from new QFs?**

A. No. This approach will overstate the adjustment since it does not consider the replacement cost of the power not produced by the QFs. However, the trend analysis does point out the level of potential risk to ratepayers if PGE's poor forecasting performance continues in this case. Staff does support an approach that assumes all of the new QFs coming online will perform the same as the previous QF's already on PGE's system. This is simply the most logical approach to forecasting this power cost category. Staff realizes there has been a large increase in the total number of QFs set to produce power for PGE customers. In 2018, QF's made up roughly [**Begin Confidential]** [redacted] **[End Confidential**] of total power costs. In 2020, they are projected

[3] Staff/402 PGE Response to Staff DR No.8.

to make up roughly **[Begin Confidential]** [redacted] **[End Confidential]**. This represents over a **[Begin Confidential]** [redacted] **[End Confidential]** increase in costs. This is somewhat uncharted territory for PGE and its customers. Staff finds that it is important to both produce a reasonable forecast and protect ratepayers and shareholders from the potential risk of lower than expected power production. Because the dramatic increase in QFs has occurred in only the last two years, Staff recommends an adjustment to the forecast so that rates are set at a reasonable rate, but also recommends a more extensive true-up due to the lack of historic actuals compared to the new QFs. Staff recommends that the Company re-run MONET, so that **[Begin Confidential]** [redacted] **[End Confidential**] of the total QF power is provided. This would provide the basis for the adjustment to total QF costs.

With the QF COD true-up agreed to in Docket No. UE 335, an additional adjustment may be needed for the differences in projected versus actual QF MWh production. One way to see this is to assume that the difference in CODs exactly matches my recommended adjustment. In that case, we have already adjusted power costs in UE 359 through my adjustment and there is no need to make an additional adjustment. There could also be an additional true-up that should apply.

Q. Please describe the additional true-up.

A. The additional true up would take into account the difference between actual MWH production from new QFs and PGE's projected MWH production. The difference in these two MWh amounts would need to be multiplied by difference in average cost of other available incremental power supply as compared to the costs of purchasing power from the new QFs.

Any change in rates charged to customers would then look at the combination of the two true-up as compared to the adjustment I recommended in this case. This results in the best forecast available in the 2020 AUT with the information available, but also limits ratepayer and shareholder risk so that this must take resource is truly a pass-through to customers.

ISSUE 2. STANDARD INPUTS

Q. Please summarize this issue and Staff's recommendation.

A. Standard inputs refer to various cost items associated with the production of power costs in operating power plants and other sources of power. The standard inputs reviewed for this testimony are forced and scheduled maintenance outages, heat rates, natural gas price forecast, Official Forward Price Curve (OFPC), fuel price and minimum operating level.

Q. Please discuss forced outage rates and scheduled maintenance?

A. PGE provided information regarding its calculation of forced outage rates in its April 15, 2019 filling and it is referenced in PGE's response to Staff Data Request No. 9, a copy of which is attached as Exhibit Staff/403. After reviewing the information, I have only one concern.

Q. What is your concern?

In the calculation of the average forced outage rate, PGE uses the 2015 through 2018 history. For purpose of Monet and the 2020 power cost projection, PGE takes the average that is three significant digits and rounds it to one decimal point. In nearly every instance, for example, Port Westward 1 and 2, Coyote, Colstrip #4, and Carty, the rounding increases the forced outage rate. In another words, as an illustrative example, 6.96 percent is rounded to 7.0 percent. Increasing the forced outage rate reduces the availability of the plant to produce power.

Q. What is your recommendation?

A. Because the rounding results in an increase to the forced outage rate in almost every case, I recommend that instead of using a rounded number to one decimal point, PGE round to two decimal points.

Q. Did you review of schedule maintenance raise any concern?

A. No. In Staff Request No. 17, a copy of which is attached as Exhibit Staff/403, I asked for information regarding the factors PGE considers in developing maintenance schedules, including the timing of when maintenance occurs. PGE's response identified several factors:

Outages are scheduled to minimize costs and include consideration for:

- *Replacement power costs:*
- *Labor costs and requirements*
- *LTSAs*
- *Forecast operation of the unit until the next scheduled outage window, and*
- *PGE's system needs for energy, capacity and operating range.*

I believe PGE's considerations are appropriate and have no concern in this area.

Q. In your review of the issues such as heat rate, natural gas price forecast and Official Forward Price Curves, fuel prices and minimum operating levels were any concerns raised on these topics?

A. My last area of concern is with the natural gas price forecast. In response to Staff Data Request No. 13, a copy of which is attached as Exhibit Staff/402, PGE states that its price forecast for 2019 was impacted by the Enbridge pipeline outage. This outage has now been repaired and I would expect the natural gas price to reflect ongoing market factors other than the Enbridge pipeline outage.

PGE provided its natural gas price forecast of 2020 and I compared that to the ICE natural gas price forecast PGE provided in response to Staff Data Request No.16, a copy of which is attached as Exhibit Staff/402.

Q. Is there any concern regarding natural gas price fuel costs?

A. Perhaps. In PGE's response to Staff Data Request No. 11, a copy of which is attached as Exhibit Staff/402, PGE states essentially that any natural gas storage capacity it has is used only within a month. This is the result of gas storage costs been recovered through a general rate case, however, this means that there is no possibility of acquiring lower-cost natural gas in one month and using it in a later month. PGE's forecast of natural gas prices in 2020 do show significant price difference across the months, going from a high of over $4/MMBTU to less than $2/MMBTU. Therefore, if natural gas storage capacity exceeds generating plant needs for natural gas, there would be opportunities to buy and store lower cost natural gas to use in place of purchasing higher priced natural gas in future months.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 359
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

June 25, 2019

WITNESS QUALIFICATION STATEMENT

NAME:	Kathy Zarate
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts, Economics Oregon State University, Corvallis, Oregon Bachelor Degree in Law Republic University, Santiago, Chile
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April 2016, with my current position being a Utility Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals.

I have approximately 10 years of professional experience in contracting and audit review work, including:

- Six years as contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business delivery, and investigating property theft.

CASE: UE 359
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

June 25, 2019

June 5, 2019

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 008
Dated May 22, 2019

Request:

Referring to PGE/100, Niman-Kim-Batzler/27, lines 3-20, in addition to replacing the projected commercial operation with the actual operation date, why does PGE not replace projected kWh produced with actual kWh produced?

Response:

PGE is complying with the terms of the stipulation adopted by the Commission through Order No. 18-405 in Docket No. UE 335. The stipulation provides that PGE will track and true up only QF commercial operation dates. Additionally, to perform a true up for QF projected generation versus actual generation would be overly burdensome.

June 5, 2019

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 011
Dated May 22, 2019

Request:

For the natural gas price forecast and cost incurred 2020, does the cost include only that natural gas used to generate power or does it include natural gas placed in storage?

For natural gas cost, how does PGE account for and include in revenue requirement, natural gas drawn from storage?

Response:

Gas reserves (i.e., stored gas) are not recorded as part of net variable power costs and thus not forecast in MONET.[1] MONET only models natural gas as it is needed to fuel our natural gas-fired plants in order to generate power. Natural gas for the Port Westward 2 (PW2) generation plant is assumed to come from storage and has an injection/withdrawal fuel factor built into the burnertip[2] price. However, the natural gas is assumed to be injected, withdrawn, and burned in the same month such that, for the purposes of forecasting net variable power costs, PGE is not adding any costs associated with natural gas that is left in storage. PW2 uses storage gas due to its unpredictable use providing ancillary services needed for load following and wind integration. Monet also includes the fixed costs associated with natural gas storage, as those are recorded in power cost accounts.

[1] Gas reserve balances are recorded in FERC account 151 and included in PGE's rate base, which is updated within a general rate case proceeding.
[2] Burnertip gas prices include both a commodity and a gas transportation component. In Monet modeling the burnertip fuel price will also include emission control chemicals and, for Port Westward 2, lube oil consumed when generating power.

June 5, 2019

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 013
Dated May 22, 2019

Request:

Referring to PGE /100, Niman-Kim-Batzel/34 [sic], lines 5-13, did the final 2019 NVPC forecast for natural gas prices includes any impacts from the Enbridge pipeline outage?

Response:

Yes. The final 2019 NVPC forecast update filed November 15, 2018 included increased forward natural gas prices due to the Enbridge pipeline rupture in British Columbia. The Sumas gas hub experienced the most significant price impact.

June 5, 2019

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 016
Dated May 22, 2019

Request:

Does ICE currently have a price forecast for 2020 monthly markets? If yes, please provide that forecast.

Response:

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

Attachment 016-A provides a May 22, 2019 ICE report on forecast power prices.

Attachment 016-B provides a May 22, 2019 ICE report on forecast natural gas prices for the ICE subsidiary in Canada.

Attachment 016-C provides a May 22, 2019 ICE report on forecast natural gas prices for the US markets.

Attachments 016-A through 016-C are protected information subject to Protective Order No. 19-112.

UE 359

Attachment 016-B

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

ICE Report: Natural Gas Prices Forecast

CASE: UE 359
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

June 25, 2019

May 14, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 001
Dated April 30, 2019

Request:

For each of QF contracts projected to come on line in 2019, please provide the following by month for each month of 2020:

a) **The number of kW projected to be supplied,**
b) **The number of kWh projected to be supplied,**
c) **The projected cost of QF power per kWh,**
d) **Total projected purchased QF power**

Response:

Attachment 001-A provides the requested information for Schedule 201 QF contracts.

a) The number of kW projected to be supplied in 2020 by each QF projected to come on line in 2019 is provided in Attachment 001-A, column R.
b) The number of kWh projected to be supplied monthly in 2020 by QFs projected to come on line in 2019 is provided in Attachment 001-A, range T10:AE161. Please note that each QF contract has different energy deliveries and pricing structures for on-peak and off-peak energy.
c) The projected cost of QF power per kWh is provided in Attachment 001-A, range AI10:AT161.
d) The total nameplate capacity for QFs projected to come online in 2019 is provided in Attachment 001-A, cell R162. The total energy projected to be delivered by these QFs in the 2020 is provided in cell AF162 with the total associated cost in cell BI162.

Attachment 001-B provides the requested information for Schedule 202 QF contracts. Attachment 001-B is protected information subject to Protective Order No. 19-112.

UE 359

Attachment 001-A

Provided in Electronic Format Only

Schedule 201 – 2019 QFs in the 2020 AUT

UE 359

Attachment 001-B

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

Schedule 202 - 2019 QFs in the 2020 AUT

May 14, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 004
Dated April 30, 2019

Request:

Given the company filings in 2015, 2016, 2017 and 2018, for each of the company filings, please provide the projected total cost of QF supplied power for new QFs coming on line in the projected test year, the actual purchased power cost for QF supplied power for that test year, the percentage of actual to projected purchased power cost.

Response:

Attachment 004-A provides projected power costs for new QFs forecast to come online in PGE's NVPC filings for the 2015, 2016, 2017, and 2018 test years, actual power costs related to QFs that achieved commercial operation date from 2015 through 2018, and the percentage of new QF actual to projected power costs for each of these years.

As presented in Attachment 004-A, PGE has extremely limited historical QF data prior to 2017 because of the small number of QF PPAs that were signed. Moreover, a QFs' ability to achieve contractual COD is contingent on a large number of uncertainties, which are largely outside the control of PGE. These uncertainties include: permitting, interconnection, transmission, and financing.

In the event new QFs will not achieve their contractually scheduled COD, customers will be refunded (or PGE will recover) the difference consistent with the QF tracking mechanism parties agreed upon in the UE 335 stipulation adopted by the Commission in Order 18-405. As such, neither customers, nor PGE bear the risk of forecasting an online date of delivery for QFs, other than their scheduled contractual COD.

Attachment 004-A is protected information subject to Protective Order No. 19-112.

UE 359

Attachment 004-A

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

QF Actual vs. Projected Costs
2015-2018

June 5, 2019

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 009
Dated May 22, 2019

Request:

For each of power plant that PGE includes in its model for which PGE owns all or a share of resources, please provide.

a) The forced outage rate for each year from 2010 through 2018
b) The forced outage rate assumed for 2020.
c) The minimum operation level and maximum output level
d) The plaint maintenance outage in terms of days; and,
e) The calculation of the forced outage rate for 2020.

Response:

PGE is objecting to this request on the basis that it is overly broad and vague. Notwithstanding its objection PGE replies as follows:

a) Forced Outage Rates from 2010 to 2018:
   - The thermal annual forced outage rates for 2010 to 2018 are provided in Attachment 009-A.
   - The hydro annual forced outage rates for 2010 to 2018 are provided in Attachment 009-B.
   - Wind generation is based on a five-year rolling average actual generation which has the forced outage rate already built-in. PGE's Biglow Canyon and Tucannon River wind plants availability starting with 2013, as presented in PGE's Quarterly Power Supply Updates, is provided in Attachment 009-E.
   - Solar forced outage rates are not explicitly modeled in MONET as energy output for PGE owned solar resources (i.e. Prologis 2, Sunway 3, Baldock, and Portland Public Schools Solar) are based on third party estimates.

b) Attachment 009-C provides forced outage rates assumed for the 2020 AUT.
The requested information can also be found here:

- The thermal forced outage rates assumed for the 2020 AUT are shown in the file "SumM610PUC10-00f-2020 AUT.xlsx", cells J89:U97 provided in the Initial Filing. The development of the FORs were described in the files in the "Vol 3 - Thermal\Thermal Forced Outage" folder, provided as part of the April 15, 2019 information filing.
- The hydro forced outage rates assumed for the 2020 AUT are 0% for all plants, as described in the "Vol 4 - Hydro\Forced Outage Rates" folder, provided as part of the April 15, 2019 information filing.
- The wind forced outage rates are not explicitly modeled for the 2020 AUT, however, the 5-year rolling average used to estimate energy output will implicitly include the actual forced outages that occurred in that time frame. This was described in the "Vol 7 - Wind\Biglow\Forced Outage Rates" and "Vol 7 - Wind\Tucannon\Forced Outage Rate" folders, provided as part of the April 15, 2019 information filing.
- The Solar forced outage rates are not explicitly modeled for the 2020 AUT, however the energy output for PGE owned solar resources (i.e. Prologis 2, Sunway 3, Baldock, and Portland Public Schools Solar) are based on third party estimates. These estimates make some forced outage rate assumptions which are implicitly in Monet. These resources are modeled as contracts in Monet. For details please refer to the respective sub-folders provided in the "Vol 5 – Contracts" folder.

c) The minimum operation level and maximum output level:
   - For thermal resources are given in the "Performance Parameters" folder included by plant within the "Vol 3 – Thermal" folder, provided as part of the April 15, 2019 information filing, with one exception. The exception is that the Boardman "Performance Parameters" folder was inadvertently left out of the information filing and is provided as Attachment 009-D.
   - For Hydro resources, please refer to the "Vol 4 - Hydro\Plant Capacity" folder.
   - Wind and solar resources are non-dispatchable and range from 0 MW to full capacity. For capacity please refer to the information provided in the folders "Vol 7 - Wind\Biglow\Capacity", "Vol 7 - Wind\Tucannon", "Vol 5 - Contracts\Baldock Solar", "Vol 5 - Contracts\Portland Public Schools Solar", "Vol 5 - Contracts\Prologis Photovoltaic", and "Vol 5 - Contracts\SunWay III Photovoltaic".

d) The plaint maintenance outage in terms of days:
   - The thermal maintenance days assumed for the 2020 AUT are shown in the file "SumM610PUC10-00f-2020 AUT.xlsx", cells J77:V85 provided in the Initial Filing. The maintenance details were described in the files in the "Vol 3 - Thermal\Thermal Maintenance\Planned in 2020" folder, provided as part of the April 15, 2019 information filing.
   - For Hydro resources, please refer to the "Vol 4 - Hydro\Plant Capacity Vol 4 - Hydro\Maintenance" folder.

- For wind, the usual maintenance is captured through the 5-year rolling average of actual energy production. For details please refer to the "Vol 7 - Wind\Biglow\Maintenance" and "Vol 7 - Wind\Tucannon\Maintenance" folders.
- For PGE's owned solar resources, maintenance is not explicitly modeled for the 2020 AUT, however the energy output for PGE owned solar resources (i.e. Prologis 2, Sunway 3, Baldock, and Portland Public Schools Solar) are based on third party estimates. These estimates make some maintenance outage rate assumptions which are implicitly in Monet. These resources are modeled as contracts in Monet. For details please refer to the respective sub-folders provided in the "Vol 5 – Contracts" folder.

e) The calculation of the forced outage rates for 2020:
   - For thermal units were described in the "Vol 3 - Thermal\Thermal Forced Outage" folder with a sub-folder for each plant.
   - The hydro FOR was assumed to be 0%.
   - The wind FOR was assumed to be built into the 5-year rolling average of actual wind energy production.
   - The Solar FOR was left at whatever had been assumed in the third-party estimates of energy production.

Attachments 009-A through 009-E are protected information subject to Protective Order No. 19-112.

UE 359

Attachment 009-A

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

Thermal FOR
2010-2018

UE 359

Attachment 009-B

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

Hydro FOR
2011-2018

UE 359

Attachment 009-C

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

PGE Power Plants Forced Outage Rates
2020

UE 359

Attachment 016-D

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

Boardman Plant Parameters

UE 359

Attachment 009-A

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

Biglow Canyon and Tucannon River Wind Plants Availability
2013-Q1 2019

Staff Exhibit 403 pages 14-26 are confidential

Attachment 009-A,
Attachment 009-B,
Attachment 009-C
Attachment 009-D (zip file) and
Attachment 009-E

June 6, 2019

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to OPUC Data Request No. 017
Dated May 23, 2019

Request:

For each PGE operated resources, please provide:

a. **For each of the years 2010 to 2018, the number of days the plant was down for maintenance, and the dates of the maintenance period.**
b. **The number of days and dates for planned maintenance for 2020.**
c. **Describe the factors considered such as cost of replacement power in adopting the timing of the 2020 maintenance for the resources.**
d. **Does the scheduling of maintenance minimize power costs to customers or are there others considerations?**

Response:

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

a. Please refer to the files provided as part of the initial documentation filing in "Vol 3 - Thermal\Thermal Maintenance\Historical". There are files for each thermal plant which show historic days of maintenance. PGE does not include wind and solar maintenance data in this response because: 1) the modeling of wind generation is based on a five-year rolling average of actual generation which already includes plant maintenance; and 2) for PGE's solar resources, maintenance is not explicitly modeled in MONET because the energy output for these resources is based on third-party consultant studies that include a maintenance assumption.

   Attachment 017-A provides maintenance information for PGE hydro plants from 2011 to 2018. The hydro maintenance data was retrieved by PGE from MicroGADS (Generating Availability Data System)[1] annual NERC (North American Electric Reliability Corporation) reporting. PGE is providing hydro maintenance data starting with 2011

[1] For more information on MicroGADS see here:
https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

because prior to 2011, PGE hydro plant operators did not record plant outage events in MicroGADS reports.

Attachment 017-A is protected information and subject to Protective Order No. 19-112.

b. Please refer to the files provided as part of the initial documentation filing in "Vol 3 - Thermal\Thermal Maintenance\Planned in 2020", for thermal plants, and "Vol 4 - Hydro\Maintenance", for the hydro plants. Attachment 017-B provides the planned maintenance for the Biglow Canyon and Tucannon River wind plants in 2020. Solar resources maintenance data is included in the third-party consultant studies providing the estimated energy output of these resources.

Attachment 017-B is protected information subject to Protective Order No 19-112.

c. When setting outage schedules several factors are considered. The factors vary depending on the technology of the generator and the services it can provide. For all outages, the PGE system need for capacity, operating range and energy is considered. Typically, units will not be taken off line for an outage if there is a high system need for the services of the unit. Many of PGE's gas plants have LTSAs (Long Term Service Agreements), that dictate the operating interval for unit outages. For hydro projects all outages try to avoid potential impact with fish operations. Run of river hydro projects are generally scheduled for outage during the low water period. At these facilities there is typically more generating capacity than water available in the low flow period of the year. The water available can be generated on the other units that are in service. On hydro projects which have the ability to shape water during the day, outage planning will take into account additional factors including the PGE system need for capacity within the hour. Typically, the within hour need for capacity is high in the summer and in the springtime during the freshet. Outages will not be placed in these time windows. During the winter period of mid- November – late February no outages are planned to reserve plant capacity for potential high load events. For coal plants, outages are generally planned in the spring and can last 30 to 60 days depending on the required outage work. Outages are placed at this time because the power prices are generally low, and the plants will normally be off line. Gas units that are combined cycle also tend to be off line in the spring due to low power prices. This would be the ideal time to take the outage. However, the LTSA's impacts must be considered in the outage placement and may place the outage in a different period of the year. Combined cycle gas plants typically have a short outage in the fall to wash the compressor and check the unit prior to the winter season. Gas plants that are simple cycle tend to be very flexible with a low minimum generation level and are needed most during high capacity events in the summer and in the spring time during the freshet. Outages for simple cycle gas plants will be placed outside this window if allowed within the LTSA.

d. Outages are scheduled to minimize costs and include considerations for:

- Replacement power costs;
- Labor costs and requirements;
- LTSAs;
- Forecasted operation of the unit until the next scheduled outage window; and
- PGE's system needs for energy, capacity and operating range.

UE 359

Attachment 017-A

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

Hydro Plants Maintenance
2011-2018

UE 359

Attachment 017-B

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

2020 PGE Wind Plants Planned Maintenance