BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335
GENERAL RATE CASE

PORTLAND GENERAL ELECTRIC

Joint Testimony in Support of the
Net Variable Power Cost Stipulation

Direct Testimony of

Scott Gibbens, OPUC

William Gehrke, CUB

Bradley R. Mullins, AWEC

Mike Niman, PGE

August 22, 2018

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I. Introduction

Q. Please state your names and positions with your respective organizations.

A. My name is Scott Gibbens. I am a Senior Economist for the Public Utility Commission of Oregon (OPUC) Staff. My qualifications appear in Staff Exhibit 101.

My name is William Gehrke. I am an Economist for the Oregon Citizens' Utility Board (CUB). My qualifications appear in CUB Exhibit 101.

My name is Bradley Mullins. I am an independent consultant testifying on behalf of the Alliance of Western Energy Consumers (AWEC). My qualifications appear in AWEC Exhibit 101.

My name is Mike Niman. I am the Manager of Financial Analysis for Portland General Electric (PGE). My qualifications appear in PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. Our purpose is to describe and support the stipulation (the Stipulation) between OPUC Staff (Staff), CUB, AWEC, Fred Meyer Stores and Quality Food Centers, Division of the Kroger Co. (Kroger), Wal-Mart Stores Inc. (Walmart), Calpine Solutions (Calpine), and PGE (the Stipulating Parties) resolving all issues identified by the Stipulating Parties related to PGE's 2019 forecast of net variable power costs (NVPC). A copy of the Stipulation is provided as Stipulating Parties Exhibit 201. While there are other parties to this case, none participated in settlement discussions and we are not aware of any who oppose the Stipulation.

Q. What is the basis for the Stipulation?

A. PGE filed its initial forecast of 2019 NVPC on February 15, 2018 as part of its general rate case filing (UE 335). PGE's NVPC forecast was updated on March 30 and July 6, 2018.[1] On April 17, parties held a workshop to discuss issues and review PGE's Multi-Area Optimization Network Energy Transaction power cost forecasting model (MONET). Staff, AWEC, and CUB submitted opening testimony on May 24, 2018 and PGE filed reply testimony on June 21, 2018. The parties held settlement discussions on June 12, June 28, and June 29, 2018. At the June 28 and 29 meetings, parties reached an agreement that they found reasonable for settlement. The Stipulation reached at the June 28 and 29 meetings resolves all NVPC-related issues raised by parties in this docket (UE 335).

Q. What power cost issues were raised by Staff, AWEC, and CUB in testimony and resolved in this settlement?

A. The issues that were raised and settled are:

- Western Energy Imbalance Market (Western EIM);
- California-Oregon Border (COB) Trading Margins;
- Wind Resource Capacity Factor;
- Market Forward Price Curve and Hedging Costs;
- Qualifying Facilities;
- Headwater Benefits Study (HWBS);
- Capacity Agreement;
- Production Tax Credits;
- Bonneville Power Administration (BPA) Wheeling Rates;

[1] PGE will provide three more 2019 NVPC forecast updates on September 28, November 6, and November 15.

- Carty Gas Supply Costs;
- MONET Code Review; and
- North Mist Expansion Project (NMEP).

We explain the resolution of each of these issues below.

Q. Are there any remaining issues related to NVPC not addressed in the Stipulation?

A. No. The Stipulation addresses and settles all NVPC-related issues in Docket No. UE 335. This Stipulation does not address or resolve any other issues related to the general rate case portion of this docket.

II. Stipulated Issues

A. Western EIM, COB Trading Margin, Wind Capacity Factor, and Market Forward Price Curves / Hedging Strategy

Q. Please describe the issue regarding the Western EIM.

A. Staff raised concerns regarding PGE's projected benefits resulting from the participation in the Western EIM. To address their concerns, Staff recommended that PGE estimate a Western EIM benefit based on historical data, preferably 12 months of actual results from PGE's participation in the Western EIM.

Q. Please describe the issue regarding the COB Trading Margins.

A. Staff identified concerns regarding PGE's method for forecasting benefits attributable to trading activity at COB. Staff proposed a different methodology of calculating these benefits attempting to account for daily variation in prices and historical transactions.

Q. Please describe the issue regarding the Wind Resource Capacity Factor.

A. Both Staff and AWEC raised concerns regarding PGE's originally forecast capacity factors for utility-owned wind facilities. To address their concerns, Staff recommended PGE's wind capacity factor be calculated using: 1) the median between the original expected capacity factor included as part of the prudence review and the now-current projected output; or 2) the higher of the current expected capacity factor or the original 75% probability of exceedance capacity factor. Alternatively, AWEC recommended PGE's wind capacity factor be calculated using a 75/25 blend between resources original request for proposal (RFP) estimates and actual wind capacity factors.

Q. Please describe the issue regarding market forward price curves and PGE's hedging strategy.

A. AWEC argued that PGE overstates forward market prices relative to actual market prices. To support their position, AWEC performed an analysis comparing historical market forward prices to average monthly settled spot prices recorded from 2006 through 2017. Based on their analysis, AWEC recommended reducing current market forward prices by the percentage difference between the historical market forward prices and the final settled spot prices. Additionally, based on their market forward price curve analysis, AWEC recommended that only 80% of the costs and benefits of PGE's hedging gains and losses be included in customer prices.

Q. Have parties resolved these issues in this settlement?

A. Yes. For settlement purposes, PGE will reduce its 2019 NVPC forecast by $4.5 million related to the issues as a group described above. Parties agreed that the $4.5 million reduction to PGE's 2019 NVPC forecast and the agreement regarding the four items below represent appropriate and reasonable resolutions for these issues. Parties further agreed to the following:

1. PGE's method to calculate Western EIM benefits will not change at this time; however, PGE will provide Staff information detailing how both base dispatch cost savings and flex reserve savings are captured in PGE's actual Western EIM benefit results and why PGE is unable to separate the two.[2]
2. PGE's method of forecasting COB trading margins will not change at this time; however, PGE will continue to investigate methods to increase the granularity and improve the modeling of COB trading margins.

[2] Stipulating Parties Exhibit 202 provides PGE's response to OPUC Data Request No. 322 including this information.

3. PGE's method of forecasting wind capacity factor will not change at this time; however, PGE will not oppose a request from Parties that the Commission open an investigation into the modeling of capacity factors for wind resources.
4. PGE's modeling of market forward price curves and PGE's hedging strategy will not change at this time.

B. Qualifying Facilities (QFs)

Q. Please describe the issue regarding QFs.

A. AWEC and CUB raised concerns regarding the modeling of QFs in MONET and recommended that the expected online date of any new QF be adjusted using the Contract Delay Rate (CDR) methodology the Commission approved in PacifiCorp's 2018 Transition Adjustment Mechanism proceeding. OPUC Staff agreed with PGE's proposed method to track and true-up QF commercial online dates (CODs) with some minor modifications.

Q. Have parties resolved this issue in this settlement?

A. Yes. Because PGE does not have sufficient QF historical information on which to base the CDR methodology and the QF tracking mechanism that PGE proposed in PGE Exhibit 300 is a simple and straightforward method to ensure that accurate online delivery dates are properly reflected in customer prices, Parties agreed with PGE's proposed method to track and true-up the QF CODs with Staff's modifications as outlined in Staff Exhibit 200 and described below:

- PGE will update the QF CODs through the final MONET update in each year's power cost proceeding.[3]

[3] For year without general rate cases, this would apply to PGE's Annual Update Tariff (AUT filing).

- PGE will file deferred accounting applications under ORS 757.259 to defer the difference between actual and forecasted QF costs to recover or credit the variance in QF costs in the next NVPC proceeding.
- PGE will include any cure period payments within the proposed methodology.

It should be noted that some parties agreed to this methodology based on the expectation that PGE's current exposure to QF costs would be temporary in nature. If this turns out to be incorrect, some parties may advocate for a change to the methodology in a future case. Once PGE has sufficient QF historical information, some parties may re-examine the applicability of the CDR methodology or another alternative.

Q. Please explain how PGE will determine the variance between actual and forecasted QF costs for 2019 and forward?

A. As described in PGE Exhibit 300, PGE will determine the variance to be refunded or collected from customers by re-running the final November 15 NVPC MONET forecast and replacing the estimated QF CODs with actual recorded CODs.

C. Headwater Benefits Study (HWBS)

Q. Please describe the issue regarding the HWBS.

A. Pursuant to a technical conference discussion on April 17, 2018, PGE provided Staff on May 23, 2018 with an electronic copy of material in support of PGE's proposed change to the NVPC forecast associated with correcting and including the results of the 2016-2017 HWBS.

Q. Have parties resolved this issue in this settlement?

A. Yes. Parties are satisfied with PGE's process and documentation and agree to PGE including the corrected 2016-2017 Headwater Benefits Study for establishing average expected base outputs for PGE's hydro resources. PGE has incorporated the corrected 2016-2017 Headwater Benefits Study into the July 6, 2018 NVPC update.

D. Capacity Agreement

Q. Please describe the issue regarding the Capacity Agreement.

A. Staff questioned the inclusion and the timing of the capacity agreement in Step 0H of PGE's 2019 initial NVPC forecast executed pursuant to the outcome of Docket No. 1892. Staff argued that they did not have access in this docket to the financial analysis supporting the selection of the top five contracts in PGE's 2017 bilateral negotiations which included the capacity agreement mentioned above.

Q. Have parties resolved this issue in this settlement?

A. Yes. Parties agreed with the inclusion of the capacity agreement in PGE's 2019 NVPC. Additionally, PGE agreed to provide Staff access and the ability to review the financial analysis that PGE conducted for the capacity agreement. Parties also agreed with the timing of the capacity contract.

E. Production Tax Credits (PTCs)

Q. Please describe the issue regarding PTCs.

A. AWEC questioned the PTC price PGE included in the 2019 NVPC forecast and the PTC customer benefits related to the timing of the Biglow 2 in-service phase-in. To address their concerns, AWEC recommended increasing the PTC per kilowatt-hour rate and adjusting the PTC phase out timing associated with Biglow 2.

Q. Have parties resolved this issue in this settlement?

A. Yes. Parties agreed that PGE will update the PTC rate pursuant to the most current forecast of the applicable Gross Domestic Product deflator available prior to PGE's November 6, 2018 NVPC update. Regarding the PTC customer benefits associated with the Biglow 2 in-service date, parties agreed to no change in MONET's modeling of the PTC phase out for Biglow 2.

F. BPA Wheeling Rate

Q. Please describe the issue regarding the BPA wheeling rates.

A. AWEC questioned PGE's escalation of the BPA wheeling rate for the period October 1, 2019 through December 31, 2019. PGE calculated an average rate escalation based on eight prior BPA transmission rate case periods starting with 2002 to estimate an escalation rate to BPA wheeling rates prior to the completion of BPA's 2020 rate case (BP-20). Based on the outcome of BPA's 2018 rate case (BP-18) and the current uncertainty over transmission rates that will be established in BP-20, AWEC recommended that PGE maintain BPA wheeling rates at their current level.

Q. Have parties resolved this issue in this settlement?

A. Yes. Parties agreed that PGE will replace the current escalation factor used for BPA wheeling with a flat increase of $500,000 for the period between October 1, 2019 and December 31, 2019.

G. Carty Gas Supply Costs

Q. Please describe the issue regarding the Carty Gas Supply Costs.

A. Staff questioned PGE's decision on the size of the 25-mile pipeline from the Gas Transmission Northwest (GTN) mainline to Carty (Carty Lateral) and proposed a reduction in PGE's 2019 NVPC forecast associated with the capacity of the Carty Lateral exceeding Carty's fuel needs.

Q. How did parties resolve this issue in this settlement?

A. Parties agreed to no adjustment related to Carty gas supply costs. However, PGE will provide to Staff the following:

- The compressor horsepower required to bring Carty inlet gas pressure under a 16-inch pipeline up to minimum operating requirements at Carty (Option A).
- The compressor horsepower, if any, required to bring Carty inlet gas pressure under a 20-inch pipeline up to minimum operating requirements at Carty (Option B).

In addition, parties agree that PGE will compare, using the cost assumptions from PGE's Carty lateral cost estimates, as provided in Staff/303, Kaufman/367-369, the cost of a 16-inch pipeline with both a single and redundant compressor sized as described above (Option A) with the cost of a 20-inch pipeline with a single and redundant compressor, if any, as sized above (Option B).[4]

H. MONET Code Review

Q. Please describe the issue regarding the MONET Code Review.

A. CUB raised concerns regarding unused spreadsheets, source codes, and codes left from various code enhancements that are currently embedded in MONET. To address their concerns CUB proposed that an independent consultant be engaged to review PGE's MONET model in order to suggest potential maintenance of the model.

Q. Have parties resolved this issue in this settlement?

A. Yes. Parties agreed that PGE will host a workshop to provide CUB and other interested parties an in-depth overview of the MONET model and work collaboratively with parties to address

[4] Stipulating Parties Exhibit 203 provides PGE's first supplemental response to OPUC Data Request No. 298 including this information.

any concerns. If concerns remain after the workshop, PGE will work with Parties to determine the proper parameters requiring further analysis and identification of a third-party consultant(s) to review the MONET model and address the remaining concerns. In the event that a consultant is engaged, Parties agree to allow PGE to defer any costs involved in conducting the third-party review, subject to an earnings review.

I. North Mist Expansion Project (NMEP)

Q. Please describe the issue regarding the NMEP.

A. Staff recommended that PGE update the NMEP expected in-service date in subsequent 2019 NVPC updates through the final NVPC update scheduled for November 15, 2018.

Q. Have parties resolved this issue in this settlement?

A. Yes. Parties agree that the North Mist Expansion Project expense forecast is reasonable and that PGE will continue to update the in-service date through the final NVPC update scheduled on November 15, 2018.

III. Recommendation to the Commission

Q. What is your recommendation to the Commission regarding the adjustments contained in the Stipulation?

A. The Stipulating Parties recommend and request that the Commission approve these adjustments. Based on careful review of PGE's, OPUC Staff's, CUB's, and AWEC's filings; consideration of the documentation provided in PGE's Minimum Filing Requirements; thorough discovery conducted by parties in Docket No. UE 335, including approximately 50 data requests focused on power cost issues; and thorough discussion of the issues during the settlement conferences, we believe the proposed adjustments represent appropriate and reasonable resolutions to all issues in this docket. Rates reflecting these adjustments will be fair, just, reasonable, and provide PGE with adequate revenues consistent with the standard in ORS 756.040.

Q. Does this Stipulation resolve all NVPC-related issues raised by parties in this docket (UE 335)?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

IV. List of Exhibits

Stipulating Parties Exhibit	Description
201	Net Variable Power Cost Stipulation
202	PGE's response to OPUC Data Request No. 322
203	PGE's first supplemental response to OPUC Data Request No. 298

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 335

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.	**NET VARIABLE POWER COST STIPULATION**

This Net Variable Power Cost Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), and the Alliance of Western Energy Consumers ("AWEC") (collectively, the "Stipulating Parties").

PGE filed this general rate case on February 15, 2018. The filing included thirteen separate pieces of testimony and exhibits. PGE also provided to Staff and other parties voluminous work papers in support of its filing. Since that time, Staff and intervening parties have analyzed PGE's filing and work papers, and submitted more than 520 data requests obtaining additional information. Two schedules were set by the Administrative Law Judge in this matter: one for net variable power cost ("NVPC") issues, and the other for general rate case issues. Pursuant to the schedules, a NVPC workshop was held on April 17, 2018, and parties filed opening testimony on NVPC issues on May 24, 2018. PGE filed reply testimony on June 21, 2018. A workshop and settlement conference for NVPC issues were held on June 12 and June 28, 2018. As a result of those discussions, the Stipulating Parties have reached a compromise settlement of all NVPC issues, as described in detail below. No other parties raised issues in this docket regarding NVPC.

TERMS OF PARTIAL STIPULATION

1. This Stipulation resolves all NVPC issues raised in this docket.

2. Western Energy Imbalance Market ("Western EIM"), California-Oregon Border (COB) Trading Margins, Wind Capacity Factor, and Market Curves/Hedging Strategy. Forecast power costs will be reduced by $4.5 million in a compromise settlement of the Western EIM, COB trading margins, wind capacity factor, and market forward curves/hedging strategy issues raised in this docket. In addition, the Stipulating Parties agree to the following:

   a. PGE will provide Staff information through a data response detailing how both base dispatch cost savings and flex reserve savings are captured in PGE's actual Western EIM benefit results and why PGE is unable to separate the two.

   b. PGE will continue to investigate methods to increase the granularity and improve the modeling of COB margins.

   c. PGE agrees that it will not oppose a request for an investigation into the modeling of capacity factors for wind resources.

3. Qualifying Facilities. The Stipulating Parties agree to the adoption of the method to track and true-up the on-line dates for Qualifying Facilities ("QF") described in PGE Exhibit 300, with Staff's modifications as outlined in Staff Exhibit 200. The method is:

   a. PGE will update the QF Commercial Operation Dates ("COD") through the final MONET update in each year's power cost proceeding.[1]

[1] For years without general rate cases, this would apply to PGE's Annual Update Tariff (AUT filing).

b. PGE will file deferred accounting applications to defer the difference between actual and forecasted QF costs to recover or credit the variance in QF costs in the next power cost proceeding.

c. PGE will include any cure period payments within the proposed methodology.

d. As described in PGE Exhibit 300, the variance to be refunded or collected from customers will be determined by re-running the final November 15 NVPC MONET forecast and replacing the estimated QF CODs with actual recorded CODs.

4. <u>Headwater Benefits Study</u>. The Stipulating Parties are satisfied with PGE's process and documentation and agree to the inclusion of the corrected 2016-2017 Headwater Benefits Study for establishing average expected base outputs for PGE's hydro resources in this docket. PGE has incorporated the corrected 2016-2017 Headwater Benefits Study into the July 6, 2018 NVPC update.

5. <u>Capacity Agreement</u>. The Stipulating Parties agree to the inclusion in NVPC of PGE's firm capacity agreement, executed pursuant to the outcome of Docket No. UM 1892. PGE will provide Staff access and the ability to review the financial analysis that PGE conducted for this capacity agreement.

6. <u>Production Tax Credits</u>. The Stipulating Parties agree that PGE will update the Production Tax Credit ("PTC") rate pursuant to the most current forecast of the applicable Gross Domestic Product deflator available prior to PGE's November 6, 2018, MONET update. The parties agree to no change in MONET's modeling of the PTC phase-out for Biglow 2.

7. <u>BPA Wheeling Rate</u>. PGE will replace the proposed escalation factor used for BPA wheeling with a flat increase of $500,000 for the period between October 1, 2019, and December 31, 2019.

8. Carty Gas Supply Costs. There will be no adjustment for Carty gas supply costs. PGE will provide Staff the following:

   a. The compressor horsepower required to bring Carty inlet gas pressure under a 16-inch diameter pipeline up to minimum operating requirements at Carty (Option A);

   b. The compressor horsepower, if any, required to bring Carty inlet gas pressure under a 20-inch diameter pipeline up to minimum operating requirements at Carty (Option B); and

   c. A comparison, using the cost assumptions from PGE's Carty Lateral cost estimates, as provided in Staff/303, Kaufman/367-369, the cost of a 16-inch diameter pipeline with both a single and redundant compressor sized as described above ("Option A") with the cost of a 20-inch diameter pipeline with a single and redundant compressor, if any, as sized above ("Option B").

9. MONET Code Review. The Stipulating Parties agree to PGE's proposal put forth in PGE Exhibit 1400 regarding review of the MONET code. PGE will host a workshop to provide CUB and other interested parties an in-depth overview of the MONET model and work collaboratively with parties to address any concerns. If concerns remain after the workshop, PGE will work with Parties to determine the proper parameters requiring further analysis and identification of a third-party consultant(s) to address the remaining concerns. In the event that a consultant is engaged, Parties agree to allow PGE to defer any costs involved in conducting the third-party review, subject to an earnings review.

10. North Mist. The Stipulating Parties agree that the North Mist Expansion Project expense forecast is reasonable. PGE will continue to update the in-service date of the North Mist Expansion Project through the final NVPC update scheduled on November 15, 2018.

11. The Stipulating Parties recommend and request that the Commission approve the adjustments and provisions described herein as appropriate and reasonable resolutions of the identified issues in this docket.

12. The Stipulating Parties agree that this Stipulation is in the public interest, and will contribute to rates that are fair, just and reasonable, consistent with the standard in ORS 756.040.

13. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all of the Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in the instant or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

14. The Stipulating Parties have negotiated this Stipulation as an integrated document. The Stipulating Parties, after consultation, may seek to obtain Commission approval of this Stipulation prior to evidentiary hearings. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right: (i) to withdraw from the Stipulation, upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation, in whole or material part, or adds such material condition; (ii) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this

Stipulation; and (iii) pursuant to ORS 756.561 and OAR 860-001-0720, to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission's final order. Nothing in this paragraph provides any Stipulating Party the right to withdraw from this Stipulation as a result of the Commission's resolution of issues that this Stipulation does not resolve.

15. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Stipulation throughout this proceeding and in any appeal, and provide witnesses to support this Stipulation (if specifically required by the Commission), and recommend that the Commission issue an order adopting the settlements contained herein. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

16. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 21st day of August, 2018.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

ALLIANCE OF WESTERN ENERGY CONSUMERS

DATED this 21st day of August, 2018.

PORTLAND GENERAL ELECTRIC
COMPANY

P.P. Kaylie Klein
STEPHANIE ANDRUS

STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

CITIZENS' UTILITY BOARD
OF OREGON

ALLIANCE OF WESTERN
ENERGY CONSUMERS

DATED this 21st day of August, 2018.

PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

CITIZENS' UTILITY BOARD
OF OREGON

ALLIANCE OF WESTERN
ENERGY CONSUMERS

DATED this 17th day of August, 2018.

____
PORTLAND GENERAL ELECTRIC COMPANY

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STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

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CITIZENS' UTILITY BOARD OF OREGON

____
ALLIANCE OF WESTERN ENERGY CONSUMERS

July 12, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 322
Dated June 28, 2018

Request:

Please provide an update to Staff DR No. 168, which asks for actual EIM benefits realized by the Company to date. In the Company's response please separately list dispatch benefits and flexible reserve savings from October 2017 through present.

a. **If the Company believes it is unable to separate dispatch and flexible reserve benefits, please provide a narrative explanation why this is the case. In your response, please address why PGE could not replicate CAISO or PacifiCorp's benefit calculation methodology which is able to differentiate between dispatch and flexible reserve savings.**

Response:

PGE objects to this request to the extent that it calls for speculation. Notwithstanding this objection, PGE replies as follows.

Table 1 below, provides PGE's current assessment of EIM benefit by month for PGE's generating resources that are 'biddable' resources in the EIM market. PGE's evaluation of benefits can change subject to CAISO's settlement timeline.

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 amount of flexible reserves needed to meet the EIM requirements.

The sub-hourly market instructions issued by the CAISO result in CAISO credits and charges. As described in its response to OPUC Data Request No. 168, PGE compares the CAISO credits and charges against the costs of the associated incremental generation that PGE either incurs or avoids to produce an assessment of actual benefits. Collectively, this is the sub-hourly dispatch savings from PGE's participation in the EIM.

In PGE's *forecast* of EIM benefits, PGE also estimated sub-hourly dispatch savings. However, in the methodology, PGE took two steps. First, it estimated sub-hourly dispatch savings prior to reductions in flexible ramping requirements in the real-time market. Second, it reduced flexible ramping requirements and estimated the *additional* sub-hourly dispatch cost savings that result from holding fewer reserves. That is, the lower flexible ramping requirements can provide PGE with additional dispatch flexibility and lead to greater sub-hourly dispatch cost savings. In PGE's actual EIM benefits, the CAISO credits and charges capture both drivers of the sub-hourly dispatch savings.

PGE is not aware of CAISO or PacifiCorp assigning *monetary* amounts to flexible reserve savings on an *actual* basis. In the case of CAISO, the Western EIM Benefits Reports provide 'flexible ramping procurement diversity savings' measured in MWs, not dollars. Similarly, in the case of PacifiCorp, PGE is aware of PacifiCorp's *forecast* methodology that forecasts the benefit associated with 'reduced flexibility reserves' by reducing the regulating reserve requirement modeled in the company's GRID model. In general, this is a similar concept to the second step PGE took in *forecasting* additional sub-hourly dispatch cost savings by lowering flexible ramping requirements in the E3 study. However, it is not a distinct value in PGE's *actual* EIM benefits, because CAISO credits and charges do not distinguish flexible reserve savings from other generator movement that results from the CAISO market instructions.

Table 1: PGE EIM Benefit by Month

October 2017	November 2017	December 2017	January 2018	February 2018	March 2018	April 2018
$435,583	$478,268	$579,084	$719,800	$628,614	$960,008	$573,566

PGE's evaluation of benefits after April (e.g., May and June) is not yet complete.

August 1, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE's *First Supplemental* Response to OPUC Data Request No. 298
Dated August 1, 2018

<u>Request:</u>

Please provide the Carty Lateral pipeline pressures by day from January 1, 2015 to present. Please identify where these pressures were read from and the approximate pressure drop between the reading point and the junction of the Carty lateral and the GTN mainline.

<u>Response (Dated May 9, 2018):</u>

PGE objects to this request on the basis that it is unclear and seeks information that is not relevant to the decisions to be made in this proceeding. Costs regarding the Carty Lateral were examined in Docket No. UE 294, and included in costs approved by the Commission in that docket through Commission Order No. 15-356. Subject to and without waiving its objection, PGE responds as follows:

Per an email exchange with OPUC Staff, PGE is providing hourly interval gas pressures at Carty instead of daily interval data. Attachment 298-A provides the hourly actual gas pressure at Carty between June 1, 2016 and May 7, 2018. Please note that there are hourly intervals with missing data because of technological issues PGE encountered when pulling the information from the PI software. PGE monitors Carty gas pressure with pressure transmitters located at Carty, upstream of the gas turbine inlet. The gas pressures monitored and recorded at Carty help PGE ensure that the Gas Transmission Northwest (GTN) mainline is providing the adequate gas pressures required by contract.

Prior to July 29, 2016, Carty was still under construction and the gas combustion turbine was not fully tuned. As such, any gas pressures recorded prior to July 29, 2016 do not provide relevant pipeline and plant design information.

PGE does not record gas pressures at the junction of the Carty Lateral pipeline and the GTN mainline. Therefore PGE has no means for providing gas pressure differences between the reading point at the Carty Lateral – GTN mainline junction and Carty.

However, as described in the final GTN Pipeline Size Evaluation white paper provided as Attachment 298-B, when the Carty Lateral was being designed, the two year average GTN historical pressure showed a minimum gas pressure on the GTN mainline of 712.23 pounds per square inch gauge (psig). This average met the minimum gas pressure requirement of 710.2 psig for a 20 inch diameter gas pipeline, but did not meet the 738.2 psig minimum gas pressure requirement for a 16 inch diameter gas pipeline.

Attachment 298-B is protected information subject to Protective Order No. 18-047.

First Supplemental Response (Dated August 1, 2018):

On June 28, 2018, OPUC Staff verbally asked PGE the following questions:

1. The compressor horsepower required to bring Carty inlet gas pressure under a 16-inch diameter pipeline up to minimum operating requirements at Carty (Option A);
2. The compressor horsepower, if any, required to bring Carty inlet gas pressure under a 20-inch diameter pipeline up to minimum operating requirements at Carty (Option B); and
3. Compare, using the cost assumptions from PGE's Carty Lateral cost estimates, as provided in Staff/303, Kaufman/367-369, the cost of a 16-inch diameter pipeline with both a single and redundant compressor sized as described above (Option A) with the cost of a 20-inch diameter pipeline with a single and redundant compressor, if any, as sized above (Option B).

PGE's response to the above request is as follows:

- The minimum gas pressure to maintain 100% maximum plant output and efficiency is 609 psig at the Carty gas turbine (GT). Accordingly, plant output will be degraded with pressures below 609 psig and ultimately the plant will trip offline with gas pressure at approximately 550 psig.
- The pressure on the GTN mainline necessary to meet the 609 psig requirement, is a minimum of 723.7 psig for a 16-inch diameter pipeline without compression and a minimum of 695.7 psig for a 20-inch diameter pipeline without compression. PGE also included a design margin of 14.5 psig to each of these pressure requirements. Refer to Staff Exhibit 303, page 361 for this information.
- During the original evaluation of pipeline sizing prior to the construction of the Carty Lateral, PGE looked at approximately two years of gas pressure data. The daily average on the GTN mainline showed a minimum gas pressure on the GTN mainline of 712.23 psig. See Staff Exhibit 303, page 362 for this information.
- From this data, the 20-inch diameter pipeline was determined to meet Carty's maximum plant output and efficiency requirements at all times, while the 16-inch diameter pipeline would have required the construction of a compression station and a compressor horsepower (hp) estimated range of between 2,000 hp to 2,800 hp with redundancy and 1,000 hp to 1,400 hp without redundancy.
- The estimated base cost of a compression station at the time of determining the pipeline sizing required to fuel Carty was approximately $15 million, not including ongoing operations and

maintenance costs, or a redundant compressor. A redundant compressor of 1000 hp would have added an additional $1,090,000 (i.e., 1,000 hp x $1,090 $/hp), for a total cost of $16,090,000. Staff Exhibit 303, page 367 provides this information. This cost has not materially changed since that time.

- At the time of making the decision on pipeline sizing, the 16-inch diameter pipeline was estimated to cost approximately $44.1 million <u>plus</u> a minimum compressor station cost of $15 million for a minimum total cost estimate of $59.1 million, without redundancy. Whereas, the 20-inch diameter pipeline was estimated to cost a total of approximately $51.1 million, which is approximately $8 million less than the 16-inch diameter pipeline, not including redundancy. See Staff Exhibit 303, pages 367-369 for this information.
- Additionally, prior to construction of the Carty Lateral, PGE reviewed a longer period (approximately five years from 1/1/2009 to 3/3/2014) of gas pressure data on the GTN mainline that showed the lowest gas pressures of 635 psig and gas pressures below 680 psig occurring less than 1% of the time. A 16-inch diameter pipeline would be unable to fuel Carty at these pressures without compression and would likely trip the plant beginning at GTN mainline pressures of approximately 680 psig, which occurred approximately 2.5% of the time over the five-year study period. Additionally, Carty would be forced to operate at a reduced level of output using the 16-inch diameter pipeline without compression when pressures on the GTN mainline are below approximately 725 psig, which occurred approximately 21.5% of the time over the five-year study period. In contrast, a 20-inch diameter pipeline is still able to fuel Carty down to 635 psig, without tripping the plant. Carty's combined cycle combustion turbine is also able to operate at full load with limited duct firing capability using a 20-inch diameter pipeline without compression down to approximately 650 psig. The pressure on the GTN mainline was at or above 650 psig over 99.5% of the time over the 5-year study period. See Figure 1 below, for the 5-year study results.

Figure 1: GTN MGT gas pressures at - Ione Compression Station 9

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