Oregon
Kate Brown, Governor

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June 26, 2020

Via Electronic Filing

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

RE: Docket No. UE 377 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2021 Annual Power Cost Update Tariff.

Attached are Staff Testimony and Exhibits:
Cover Letter, Certificate of Service and Service List

- Exhibit 100-102,
  Exhibit 100 with confidential pages 8-11 and 14-18
  Exhibit 102 pages 17-38 is confidential and
  three confidential attachment filed in electronic format

- Exhibit 200-203,
  Exhibit 200 with confidential pages 2, 5, 7-10, 12 & 13
  Exhibit 203 confidential filed in electronic format

- Exhibit 300-303
  Exhibit 300 confidential page 3
  Exhibit 303 is confidential

- Exhibit 400-403
  Exhibit 400 with confidential pages 2, 4-6, 8 & 9
  Exhibit 403 has two confidential attachment filed in electronic format

/s/ Kay Barnes
Kay Barnes
PUC- Utility Program
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CERTIFICATE OF SERVICE

UE 377

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 26th day of June, 2020 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (503) 378-5763

CASE: UE 377
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

June 26, 2020

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

A. My name is Sabrinna Soldavini. I am a Senior Regulatory Analyst employed in the Rates and Accounting 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 or Company)'s 2021 Automatic Update Tariff (AUT) filing and Staff's proposed adjustments. I also discuss Staff's analysis of PGE's proposed gas optimization and storage benefit methodology, new energy and capacity resources, and non-price modifications to Schedule 125.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/102, PGE Response to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF STAFF'S REVIEW OF PGE'S 2021 AUT FILING

Q. Please explain the purpose of the PGE's AUT Filing.

A. Commission Order No. 08-505 authorizes 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 Net Variable Power Cost (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 concurrently with a general rate case (GRC) the Company is also able to propose changes in methodology.

Q. What updates does the Company propose in its initial filing?

A. The Company is proposing the following changes to update its 2021 NVPC:

1. Update the manner in which it forecasts EIM benefits;[1]
2. Include an NVPC benefit based on PGE's gas storage and gas resale optimization activity;[2]
3. Update NVPC to include two new BPA capacity contracts;[3]
4. Update the 2021 transmission cost forecast to account for additional PTP BPA transmission required for Wheatridge wind & solar plant, the expiration of BPA PTP transmission credits at Tucannon wind plant, and changes to BPA rates effective October 2021;[4] and

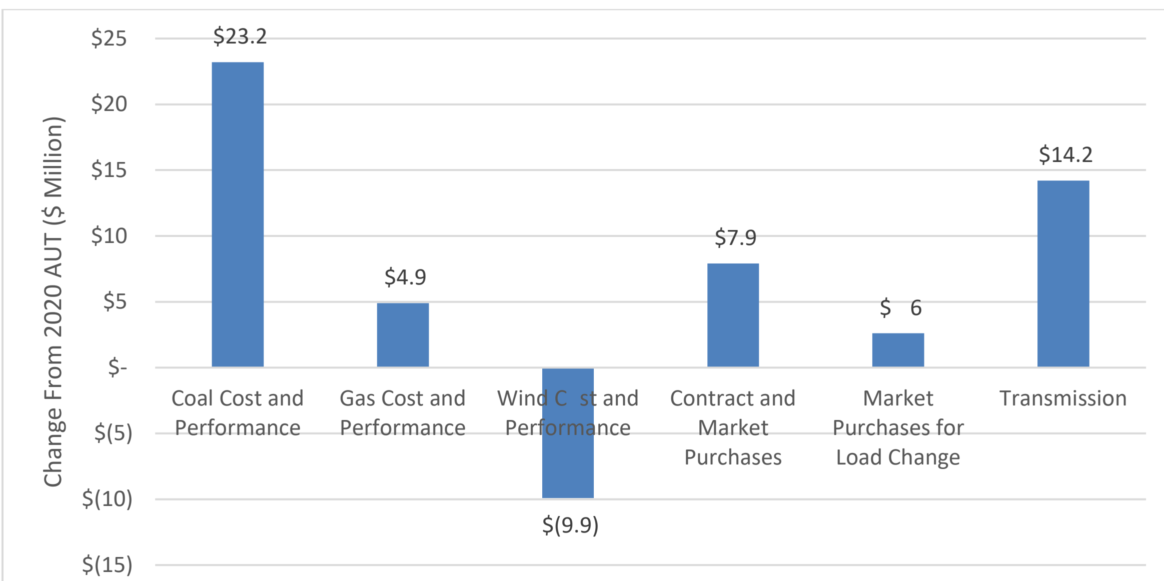
[1] PGE/100, Seulean – Kim – Batzler/8-16.
[2] PGE/100, Seulean – Kim – Batzler/16-25.
[3] PGE/100, Seulean – Kim – Batzler/26-28.
[4] PGE/100, Seulean – Kim – Batzler/36.

5. Update Schedule 125 to include annual updates to costs associated with integrating all variable energy resources as opposed to the current integration cost that includes only wind resources.[5]

Q. Please summarize PGE's 2021 AUT Filing.

A. The Company's initial filing requests a 2021 NVPC of approximately $436.2 million, which represents an increase of approximately $42.7 million when compared to the final 2020 NVPC.[6] This equates to an increase of $2.19/MWh from the final update MONET run in the 2020 AUT, from $20.02 MWh to $23.20/MWh.[7] Figure 1 below shows the change from the 2020 AUT by NVPC category.

Figure 1 NVPC Change by Category



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[5] PGE/200, Speer/9.
[6] PGE/100, Seulean – Kim – Batzler/43.
[7] *Ibid.*

Q. Has the Company filed any additional testimony since its initial filing?

A. Yes, on June 8, 2020, PGE filed supplemental testimony providing details on a power purchase agreement (PPA) executed after PGE's initial filing with the Public Utility District No. 1 of Douglas County (Douglas) for surplus capacity and energy.[8] Given the limited time frame between the Company's supplemental filing and parties' Opening Testimony deadline, Staff, intervenors, and the Company have come to an agreement by which Staff and intervenors will provide Opening Testimony on the Douglas PPA on July 9, 2020.

Q. What topics will Staff address in Opening Testimony?

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

(Staff/100, Soldavini)
1. Gas Storage and Optimization;
2. Capacity Contracts; and
3. Schedule 125 Non-Price Modifications.

(Staff/200, Enright)
4. Western Energy Imbalance Market;
5. Wholesale Transactions; and
6. Standard Inputs.

(Staff/300, Gibbens)
7. 2021 Transmission Rights;
8. Wheatridge; and
9. Load Forecast.

(Staff/400, Zarate)
10. Qualifying Facilities.

[8] PGE/300, Seulean – Kim – Batzler.

ISSUE 1. GAS RESALE AND STORAGE OPTIMIZATION

Q. Please summarize this issue in the context of the AUT.

A. In last year's AUT, in Docket No. UE 359, AWEC raised the issue of potential financial benefits associated with PGE's gas storage and transportation agreements that were not sufficiently captured in the NVPC forecast.[9] In the stipulation approved by the Commission in Order No. 19-329, PGE agreed to hold a workshop on gas optimization before filing the 2021 AUT, and further agreed to propose forecasting methods for gas optimization modeling informed by the workshop discussion.

Q. Did PGE hold a workshop on gas optimization prior to the filing of this docket?

A. Yes. PGE held a gas optimization workshop on March 4, 2020, which was attended by the Alliance of Western Energy Consumers (AWEC), Oregon Citizens' Utility Board (CUB), and Staff. PGE walked through its proposed gas optimization methodology and MONET updates. The workshop materials are included in Staff Exhibit/103.[10]

Q. How has PGE proposed to account for gas optimization in this year's AUT?

A. PGE's gas optimization proposal is comprised of two separate adjustments:

[9] Docket No. UE 359 AWEC/100, Mullins/6.
[10] Staff Exhibit/103, Soldavini/1-3, PGE Response to Staff Data Request 1.

1. Gas resale benefits related to PGE's gas operations on the Gas Transmission Northwest (GTN) Pipeline, resulting in an initial filing benefit and reduction to NVPC of approximately $600,000; and
2. Gas storage optimization benefits related to PGE's gas operations at the North Mist storage facility and the Port Westward (PW) Beaver complex, resulting in an initial filing benefit and reduction to NVPC of approximately $2.9 million.

The proposed changes result in a combined initial filing reduction to NVPC of approximately $3.5 million.

I. Gas Resale Benefits

Q. How does PGE propose to capture gas resale benefits in its power cost model?

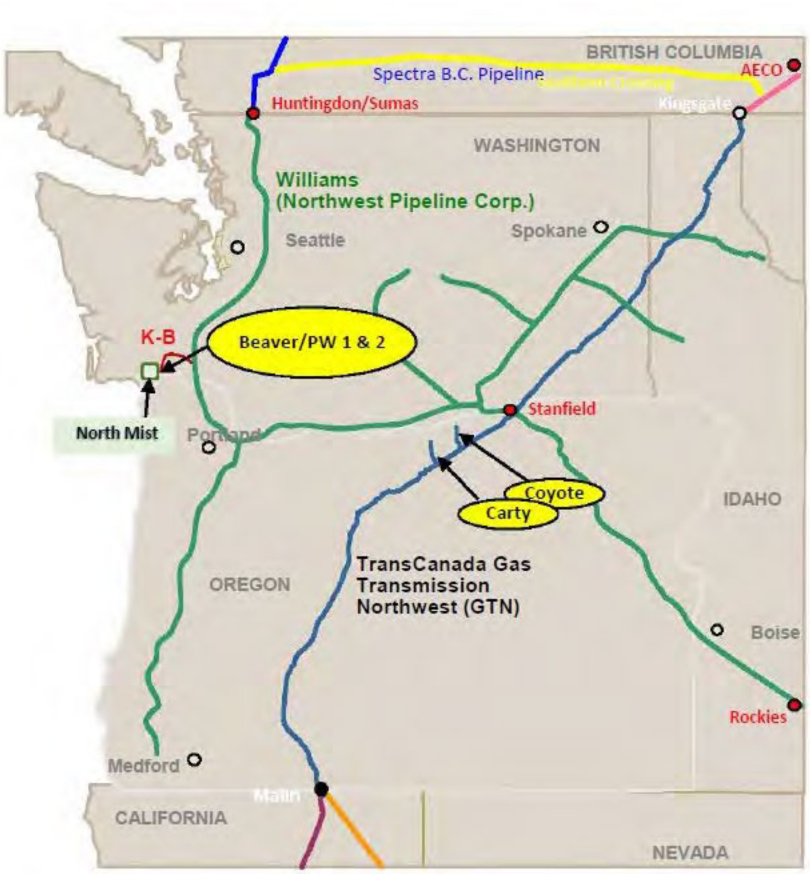
A. PGE has firm gas transportation rights of approximately 119,500 dth/day on the GTN pipeline to meet fueling requirements for its Coyote Springs (Coyote) and Carty gas thermal plants.[11] PGE's rights on the GTN pipeline also provide access to the AECO and Stanfield gas hubs (see Figure 2 below).[12]

PGE states in its testimony that AECO has historically been one of the lower cost locations in North America for purchasing natural gas, while Stanfield, which is located near Carty and Coyote, is usually more expensive due to the illiquid nature of trading at that hub.[13] Therefore, PGE is proposing to capture the gas optimization margins on the GTN pipeline as follows: if there is a gas

[11] PGE/100, Seulean – Kim – Batzler/17.
[12] PGE/102, Seulean – Kim – Batzler/1.
[13] PGE/100, Seulean – Kim – Batzler/18.

surplus in any given day, MONET will sell the surplus gas at Stanfield and potentially realize a benefit; if there is a gas deficit, MONET will purchase gas to fill the deficit, reducing the gas resale benefits. Simply put, the difference between GTN pipeline capacity and Coyote/Carty gas demand as projected by MONET on a daily basis will be multiplied by the AECO-Stanfield price spread to determine the gas optimization margins.

Figure 2 PGE Gas Market Hubs and Pipelines



Q. What assumptions does PGE's methodology rely on?

A. PGE's assumes that the gas resale benefits are based on the AECO-Stanfield price spread. PGE assumes that gas resale at Stanfield will occur as the lesser of the Sumas and Rockies forward price curves as there is no published forward price curve for Stanfield.[14] Additionally, PGE assumes that gas resale can occur when Carty and Coyote are on planned outages or are economically displaced by MONET. Staff discusses its position on these assumptions below.

Q. Does PGE add any constraints to limit gas resale activity or gas resale benefits?

A. Yes. PGE adds three additional constraints that restrict gas resale activity and resale benefits. The first two constraints limiting gas resale activity are described in PGE's testimony. PGE's methodology forbids gas resale when Coyote and Carty are experiencing forced outages. PGE states it cannot forecast power cost benefits from capturing price spreads at AECO and Stanfield during forced outages as forced outages are "not normal events that can be planned for."[15] Second, PGE restricts gas trades at Stanfield in April through November due to maintenance on the GTN pipeline. During these months, "pipeline capacity is reduced by three to 12 percent for multiple periods of time that range in duration between one and 14 days."[16]

The third constraint, which was identified by Staff in the Company's gas resale workpapers, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as an input in MONET, and ultimately artificially reduces the value gas resale optimization benefit.

[14] PGE/100, Seulean – Kim – Batzler/19.
[15] *Ibid.*
[16] PGE/100, Seulean – Kim – Batzler/20.

Q. Does Staff accept the Company's gas resale optimization methodology as proposed?

A. Generally, Staff appreciates that PGE has proposed a methodology by which customers may realize previously unaccounted for benefits of gas resale activity by the Company. However, Staff recommends one modification to PGE's methodology and one outboard adjustment in this year's AUT. Staff notes that as this is the first year in which PGE has introduced its gas optimization modeling, the parties need more time to evaluate and refine the calculation of gas resale benefits before agreeing to a methodology moving forward. Accordingly, Staff may raise additional issues regarding the methodology in PGE's AUT process next year.

Q. What is Staff's proposed modification to PGE's methodology?

A. First, Staff recommends that the Commission order the Company to remove its **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in its gas resale model. This **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** appears nowhere else in MONET as far as Staff can tell, and it is unclear why such a constraint would be necessary here and nowhere else, or why the same constraint would not be applied elsewhere in its gas resale model. Based on PGE's gas resale workpapers filed with PGE's initial application, Staff calculates that removing this constraint would lead to an increase in gas resale benefits (and a reduction to NVPC) of $213,156.

Q. Does Staff have any other concerns with the Company's proposal?

A. Yes. Staff disagrees with the Company's belief that the unpredictable nature of forced outages necessitates there can be no calculated benefit of gas resale during forced outages. In reality, PGE does buy and sell gas during prolonged forced outages as indicated by the Company in response to Staff DR 2.[17] Staff agrees with the Company that based on the provided data, such transactions seem to be limited. For example, in 2019, there were **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** forced outages at Carty and Coyote that PGE acknowledges were long enough to transact, with an average duration of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In 2018, there were **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** such events with an average duration of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

While Staff understands that making this modification to the MONET model may be difficult and may not be feasible within the timeframe of this docket, Staff believes that an outboard adjustment could be made in this AUT to capture the benefit of gas resales during forced outages. In addition, Staff believes the Company should explore options to use the forced outage rate it calculates and uses as an input in MONET to determine these benefits in future AUTs. As such, Staff proposes no methodology change in this AUT, but does propose a small adjustment to capture gas resale benefits during forced outages.

Q. What is Staff's forced outage adjustment?

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[17] Exhibit Staff/102, Soldavini/4.

A. Staff used the data provided by PGE in response to Staff DR 2, to perform a simple calculation of the potential benefits of the transactions that did occur during forced outages in 2018 & 2019, and based on the average of those two years recommends an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

II. Gas Storage Benefits

Q. Please describe natural gas storage optimization in the context of PGE's system.

A. PGE's North Mist facility has an underground storage capacity of 4.1 BCF. North Mist connects to the PW/Beaver complex via a 13-mile underground unidirectional gas pipeline.[18] When combined with PGE's firm rights of 103,305 dth/day on the Northwest Pipeline for firm delivery at the Kelso-Beaver (KB) pipeline,[19] gas storage and withdrawals allow PGE to capture seasonal natural gas market price differentials.

Q. How does PGE propose to capture gas storage optimization benefits on its system?

A. PGE plans to optimize activities at its North Mist (Mist) storage facility and PW/Beaver complex by evaluating storage and withdrawal cycles relative to forward gas prices at Sumas and Rockies to capture the price differential benefits.[20] In its proposed model, PGE first calculates a weighted average cost

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[18] PGE/100, Seulean – Kim – Batzler/22.
[19] PGE holds firm receipt rights at the Sumas market of 73,305 dth/day, and firm receipt rights at the Rockies market of 30,000 dth/day for a total of 103,305 dth/day.
[20] PGE/100, Seulean – Kim – Batzler/21.

of gas (WACOG) in storage based on inventory levels and market prices, and then models storage injections in months when natural gas prices are cheaper, and models gas withdrawals from storage in months when prices are higher, resulting in PGE's ability to capture the seasonal price differences in natural gas, resulting in a lower NVPC forecast.[21]

Q. What assumptions and constraints does PGE rely on for its gas storage benefit calculation?

A. PGE has included the following gas storage optimization constraints:

1. A limited injection period in fall and spring due to bi-annual facility testing and outage;
2. A minimum of 1.2 BCF held in storage at all times for plant reliability purposes;
3. The maximum daily gas injection rate is 56,000 dth/day and the maximum daily withdrawal rate is 120,000 dth/day. The gas withdrawal rate is ratcheted down based on storage inventory levels from 120,000 dth/day to 45,600 dth/day (at below 18 percent storage inventory);
4. Injection and withdrawal rates are reduced by 5,000 dth/day to support Port Westward 2 wind and load following ancillary services activity;
5. No availability of non-firm delivered gas from December to February.

Q. Does Staff have any concerns with PGE's proposed gas storage optimization calculation?

[21] PGE/100, Seulean – Kim – Batzler/21.

A. As with the gas resale benefit proposed by PGE, Staff appreciates the Company's proposal to incorporate gas storage optimization benefits. Staff has some reservations about certain aspects of the proposed methodology discussed below but does not at this time recommend any modifications. Staff believes that the parties will benefit from additional years' data to determine if PGE's proposed methodology does in fact sufficiently and reasonably capture gas storage optimization benefits before agreeing to a particular calculation.

Though Staff is proposing no adjustments to the Company's methodology here, Staff notes issues for future review.

Q. What issues does Staff recommend for future review?

A. One of Staff's concerns from this initial review is regarding the MONET constraint assuming no availability of non-firm delivered gas from December to February. PGE states that it does not have sufficient gas supply from firm rights and North Mist gas storage to meet PW/Beaver complex at full load each day. For months in which fueling requirements at the PW/Beaver complex exceed firm pipeline rights and North Mist storage withdrawal capability, MONET will typically purchase non-firm delivered gas to fill the need. However, the Company states it has limited access to 31,695 dth/day of non-firm delivered gas available on the Northwest pipeline, particularly during winter months for such purposes, and thus MONET assumes no availability of non-firm delivered gas in winter months.[22]

[22] PGE/100, Seulean – Kim – Batzler/22.

In response to Staff DR 4, PGE provided non-firm delivery transaction data to the PW/Beaver which does appear to confirm that between 2017 and 2019 there were limited non-firm deliveries at PW/Beaver between December and February. However, in 2019 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of non-firm deliveries were made between December and February, a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in 2018 and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in 2017. As such, Staff plans to monitor this assumption, noting that if non-firm deliveries continue to be made in the winter months, this assumption/constraint should be removed, allowing for additional gas storage benefits.

Q. Does Staff have any other issues it would like to explore moving forward?

A. Staff also wishes to continue to explore the level of granularity in PGE's modeling. Currently, PGE has set up its model to inject or withdraw in each month, meaning that the model is not taking into account that there could be injections and withdraws in the same month, or week.[23] Staff is concerned that assuming that each month has gas flows in only one direction may not be reasonable or sufficiently capture fluctuating prices within months. Staff recommends that PGE explore the feasibility of performing this calculation on a more granular level, and provide an update to parties.

[23] The exception to this is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which sees injection and storage within the same month.

ISSUE 2. NEW CAPACITY CONTRACTS

Q. What new capacity contracts is PGE proposing to include in this filing?

A. PGE has included three new capacity contracts in it 2021 AUT. In November 2018, PGE executed two capacity and energy PPAs with one counterparty. As PGE noted in its initial filing, the Company was continuing to pursue additional capacity agreements at the time, and as referenced earlier in my testimony PGE filed supplemental testimony on June 8, 2020, to include in its NVPC forecast a third energy and capacity PPA with Douglas County. Given the filing date of the supplemental testimony, Staff and intervenors will be filing additional testimony on this on July 9, 2020. Therefore, I will focus only on the two new PPAs entered into with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** here.

Q. Why is it necessary for PGE to include new capacity resources in this year's NVPC filing?

A. In PGE's 2016 Integrated Resource Plan (IRP), the Company identified a capacity need of approximately 561 MW in 2021. Subsequently, based on feedback from the Commission and parties, the Company began pursuing bilateral negotiations for available regional capacity resources. Later, in 2017, PGE asked for a waiver of the Commission's Competitive Bidding Guidelines in Docket No. UM 1892, requesting the Commission grant the waiver to facilitate the purchase of approximately 350-450 MW of resources.[24] The Commission approved PGE's waiver request in Order No. 17-386 with the condition that

[24] PGE/100, Seulean – Kim – Batzler/28.

PGE come back to the Commission before moving forward with offers that were not identified in the top five ranked indicative offers as presented in UM 1892.

Additionally, Staff notes that this is the first AUT that does not include the Boardman coal plant, a 575 MW plant, as a resource. Boardman is scheduled to be decommissioned at the end of 2020.

Q. Are the two new resources included in the 2021 NVPC forecast resources that were in the top five offers in UM 1892?

A. Yes, as PGE notes in its filing, the two new contracts were included in the top five offers in UM 1892. In total, PGE entered into three PPAs with two counterparties pursuant to Order No. 17-386. As PGE describes in its testimony, the first was a five-year PPA for 100 MW of firm capacity.[25] The first PPA had an effective date of January 1, 2019, and was included in the 2019 AUT and is currently in rates, as initially approved in Order No. 18-405.

The other two capacity and energy PPAs are those being included in this filing, which were executed in November 2018, and have an effective date of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Please describe the two new contracts.

A. The two new contracts allow PGE to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Both contracts are for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of capacity, though one contract is a **[BEGIN CONFIDENTIAL]** [redacted]

[25] PGE/100, Seulean – Kim – Batzler/27.

[END CONFIDENTIAL] while the second contract is a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What effect does the addition of these two resources have on NVPC?

A. As outlined in the Company's step log, including the two new capacity contracts **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** NVPC by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Is Staff proposing any adjustment for this issue?

A. No, Staff has reviewed the two new PPA contracts and is proposing no adjustment at this time.

Staff also notes that both contracts are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of capacity at a reservation rate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff reviewed PGE's 2016 IRP, and found that PGE estimated the average cost of an annual capacity resource based on four price scenarios was approximately \$100/kW-yr (\$8.33/kW-mo).[26] In the more recent 2019 IRP, PGE's reference case modeled a simple-cycle combustion turbine (SCCT) as the lowest capacity resource in the near term, and found a cost of capacity of \$103/kW-yr (\$8.58/kW-mo).[27] While these numbers cannot be used as direct comparators, as competitive bidding can drive down the price of resources that are actually acquired, they serve as a reference point when evaluating the reasonableness

[26] LC 66, PGE 2016 Integrated Resource Plan, page 123.
[27] LC 77, PGE 2019 Integrated Resource Plan, page 166.

of the contracts included in this filing, which both include a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than used in the 2016 and 2019 IRPs.

ISSUE 3. NON-PRICE MODIFICATIONS TO SCHEDULE 125

Q. What modification is PGE proposing to Schedule 125?

A. PGE proposes one change to Schedule 125 in its initial application. PGE proposes to modify language on Sheet No. 125-1 related to updates that will be made annually in the AUT. PGE proposes to replace the reference to "[c]osts associated with wind integration" to "[c]osts associated with integrating variable energy resources."[28] Essentially, this change would allow PGE to include annual updates to costs associated with integrating solar resources.

Q. Did PGE describe why it is necessary to make this modification now?

A. PGE provides little on the record in its initial application to support this change, noting simply that "[i]ntegration of variable energy resources is not limited to wind and reflects the realities of PGE's system more holistically."[29] PGE also noted that though it did not model non-wind variable energy resources in its initial filing it may add other resources.[30]

Q. Has PGE proposed to model other variable energy resource since its initial filing?

A. Yes. On June 15th 2020, PGE submitted an update filing notifying parties of the changes it plans to make in its July 15, MONET update. The proposed changes update the Resource Optimization Model (ROM) volumes to reflect the inclusion of Wheatridge and on-system solar projections, and modify the volumes of load following and regulation reserve margins PGE states are

[28] PGE/200, Speer/9.
[29] *Ibid.*
[30] *Ibid.*

necessary to integrate variable energy resources. As such, Staff generally assumes that this increase to reserve margin would lead to an increase in the NVPC forecast. However, PGE provided no estimate of the effect of the proposed changes on NVPC.

Q. Does PGE's proposal amount to a MONET modeling change?

A. Yes.

Q. What is Staff's recommendation?

A. Modifications to Schedule 125 are not allowed outside of a general rate case, and Staff recommends denying PGE's request to do so in this AUT filing. Even if this is the sort of the change that is permitted in between general rate cases the proposed change is not adequately supported.

PGE does not describe on the record all the ways it intends to apply this change in this and future AUT filings. For example, it is not clear whether the change would be limited to updating load following and regulation margin volumes or whether the change would have other impacts.

Further, because the proposed MONET changes were filed on June 15, 2020, rather than in PGE's initial filing on April 1, 2020, Staff has not had sufficient time to analyze how the proposed load following and regulation margin obligations were calculated, and cannot sufficiently determine how this proposed update will impact NVPC, making it difficult to assert that such changes are just and reasonable.

Staff notes that it is not opposed to the Company including solar integration costs into the NVPC forecast, recognizing that wind is not the only variable energy resource that PGE must integrate. However, PGE has provided little to no evidence on the record in this case as to why its proposed change should occur now (as opposed to prior years that saw large increases in on-system solar projections, or in its next GRC), how the updated reserve margins were calculated, or the estimated effect to NVPC of such changes.

Accordingly, Staff recommends that the Company's proposal be denied.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 377
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

June 26, 2020

WITNESS QUALIFICATION STATEMENT

NAME:	Sabrinna Soldavini
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Regulatory Analyst Energy Rates, Finance, and Audit Division
ADDRESS:	201 High St. SE. Suite 100 Salem, OR 97301-3612
EDUCATION:	Master 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 (OPUC) since August 2018 in the Energy Rates, Finance, and Audit Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have sponsored testimony before the OPUC in the following dockets: UE 350, UE 356, UE 358, UE 359, UE 374, UE 374, UE 377 (Pending), UG 347, UG 366, UG 388, UG 389 (Pending), and UG 390 (Pending). Prior to working for the Commission I was employed as a consulting analyst for MGT Consulting, primarily working on projects to assist large public school districts prepare for bond proposals through budget analysis and statistical modelling/projections of student and demographic data. From June 2015 – June 2017, 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 377
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 26, 2020

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 001
Dated May 14, 2020

Request:

Please provide a copy of all materials the Company used in the Gas Optimization workshop held on March, 4th 2020.

Response:

Attachment 001-A provides PGE's gas optimization presentation for the workshop held on March 4, 2020.

Attachment 001-B provides the excel outboard model with PGE's proposed gas optimization method presented at the March 4, 2020 workshop.

Attachments 001-A and 001-B are protected information and subject to Protective Order No. 20-100.

UE 377

Attachment 001-A

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

PGE Gas Optimization Presentation

UE 377

Attachment 001-B

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

PGE Gas Optimization Proposed Method

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 002
Dated May 14, 2020

Request:

Please refer to PGE/100, Seulean – Kim – Batzler/19, which states that MONET cannot forecast power cost benefits from monetizing price spreads between AECO and Stanfield when Carty and Coyote experience forced outages.

a. Does PGE confirm that in actual operations, PGE can monetize price spreads between AECO and Stanfield when Carty and Coyote experience forced outages?

b. If the answer to part a. above is yes, please provide the price spreads between AECO and Stanfield (expressed as the lesser of Sumas and Rockies) during each forced outage for Carty and Coyote in the years 2017, 2018, and 2019. Please provide the data in excel spreadsheet format.

Response:

a. Yes, in real operations PGE does indeed pursue gas transactions when Carty and Coyote Springs experience prolonged forced outages. PGE however does not have the ability to forecast a benefit that can potentially be realized from those transactions due to the interplay of several factors such as:

- Forced outages occur randomly and most often have short durations. As it can be seen in Attachment 002-A the vast majority of actual forced outages that occurred at Coyote and Carty from 2016 through March 2020 happened within a day and have been shorter than 24 hours in duration and PGE did not transact during those times. As provided in PGE Exhibit 100, PGE needs to maintain the supply of gas available for when the plants resume operations. PGE pursued very few gas transactions at AECO and Stanfield only when the Carty and Coyote Springs forced outages were longer than 24 hours in duration.

- PGE does not have the ability to plan for trading activities at Stanfield on an intra-day basis due to the illiquidity of the market. The market is illiquid because most physical gas consumers have filled their gas need in the Day-Ahead gas market, as such there is no supply for there to be a market to resale physical gas within the day.

PGE also notes that during prolonged forced outages we have to purchase replacement power at the market prevailing price which could be significantly higher than PGE's dispatch cost and resulting in a loss to PGE outweighing any potential benefit that could be realized from gas resales.

b. Attachment 002-A provides PGE transaction data including gas volumes transacted and prevailing market prices and spread basis at Stanfield and AECO for the time intervals longer than 15 hours when Carty and Coyote have been experiencing forced outages from January 2016 to March 2020.

Attachment 002-A is protected information subject to Protective Order No. 20-100.

UE 377

Attachment 002-A

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

PGE Gas Transaction Data during Carty and Coyote Springs Forced Outages

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 003
Dated May 14, 2020

Request:

Please refer to PGE/100, Seulean – Kim – Batzler/20, which states "during the times when maintenance is performed, the pipeline capacity is reduced by three to 12 percent for multiple periods of time that range in duration between one and 14 days, hampering PGE's ability to use its transportation rights for trading activities.

a. Please provide any evidence PGE has to support this claim.

b. Please explain how PGE has incorporated this constraint into MONET?

Response:

a. TransCanada GTN publishes a maintenance schedule annually at the following TransCanada website: http://tcplus.com/GTN/Notice/PlannedServiceOutage. Because a 2021 maintenance schedule is not yet available, PGE based the GTN pipeline maintenance derate applied in the gas optimization model on GTN's 2020 maintenance schedule as of January 7th, 2020. For additional information, please refer to the MFR for Gas Resale provided in Volume 9 (Enhancements and New Items) -> Step 0h - Gas Resale Optimization.

b. PGE has incorporated the constraint in MONET as part of the gas resale optimization by reducing the GTN pipeline capacity available for gas resale. The maintenance derate is reflected in the power cost output provided for step 0h in PGE's April 1 filing. Please see the worksheet titled "Gas Resale" for cells C10:N10 containing the maintenance derate.

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

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

Request:

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

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

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

Response:

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

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

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

UE 377

Attachment 004-A

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

PW/Beaver Non-Firm Gas Purchases
January 1, 2017 to December 31, 2019

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 005
Dated May 14, 2020

Request:

Please provide any communications with PGE's power operations team used to inform PGE's proposed methodology for capturing natural gas resale benefits.

Response:

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

Per telephone conversation with OPUC Staff on May 19, 2020, PGE is providing in Attachment 005-A the relevant email communication that informed the assumptions included in PGE's gas optimization method that PGE proposed in Exhibit 100. Per the discussion with OPUC Staff, PGE is providing relevant email communication between PGE power operations and PGE's rates and regulatory affairs and financial analysis personel actively involved in developing the gas optimization method, that occurred between January 1, 2020 and March 4, 2020, the date of the gas optimization workshop held by PGE.

Attachment 005-A is protected information and subject to Protective Order No. 20-100.

UE 377

Attachment 005-A

Protected and Subject to Protective Order No. 20-100

Provided in Electronic Format Only

PGE Communication - Gas Optimization Method

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 006
Dated May 14, 2020

Request:

Please provide any communications with PGE's power operations team used to inform PGE's proposed methodology for capturing natural gas storage optimization benefits.

Response:

Please see PGE's response to OPUC Data Request No. 005, confidential Attachment 005-A.

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 007
Dated May 14, 2020

Request:

Did PGE explore any alternative methods for capturing natural gas storage and resale benefits? If so, please provide the results of such analysis, including any excel spreadsheet models and MONET output files.

Response:

No. PGE developed the gas optimization methodology through a collaborative approach between internal teams responsible for PGE's gas operations and its MONET power cost modeling. The gas optimization methodology is a mathematical approach to value gas storage and resale benefits based on expected real-world operational constraints and actions. Additionally, PGE received feedback from external stakeholders to inform its gas optimization methodology at the gas optimization workshop held on March 4, 2020.

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 008
Dated May 14, 2020

Request:

Is the Company currently involved in negotiations to procure additional capacity for 2021? If so, does the Company have an estimate of when any proposed adjustments to its NVPC forecast would be made to reflect such capacity procurement?

Response:

As of the date of this response, PGE is not actively involved in any negotiations to procure additional capacity for 2021. PGE however did execute in May of 2020 an additional capacity agreement with the Public Utility District No. 1 of Douglas County (Douglas PUD). PGE will include the Douglas PUD capacity contract in the July 15 MONET update and submit supplemental testimony prior to that.

PGE continues to work internally to monitor its short- to mid-term capacity needs.[1] Additionally, PGE will remain engaged with owners of existing bilateral capacity to determine the availability and suitability of capacity offerings to meet PGE's capacity needs.

Should PGE execute additional capacity agreements we would update the 2021 NVPC forecast to include those agreements as soon as practicable, in an upcoming MONET update.

[1] PGE's 2019 IRP identified a capacity deficit of 240 MW in 2021 increasing to 697 MW in 2025.

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 009
Dated May 14, 2020

Request:

Have the two new capacity and energy PPAs, executed in November 2018 and included in this year's 2021 NVPC forecast been approved and/or evaluated by the Commission in any other dockets? If so, please provide the Docket No. and any relevant Commission Orders.

Response:

Yes, the new capacity PPAs (three PPAs with two counterparties) executed in November 2018 were part of the top five scoring offers presented by PGE to the Commission and stakeholders in PGE's 2016 Integrated Resource Plan (Docket No. LC 66) and in Docket No. UM 1892, PGE's Waiver for Competitive Bidding Guidelines. The capacity PPAs were also included in PGE's 2019 IRP capacity analysis (Docket No. LC 73). As provided in PGE Exhibit 100 on page 26, in August 2017 PGE filed a request to waive the Commission's then Competitive Bidding Guidelines that called for a competitive bidding process for resources greater than 100 MW and a term of more than five years. Commission Order No. 17-494[1] ultimately granted PGE's waiver but required PGE to engage the Commission before advancing offers not identified in the top five ranked indicative offers as presented in the waiver application. The three new capacity PPAs executed in November 2018 were part of the top five indicative offers presented by PGE in that docket for which the Commission approved the waiver of the Competitive Bidding Guidelines. One of the three capacity PPAs that were part of the same process was reviewed by parties and included in PGE's 2019 NVPC forecast approved by the Commission in Docket No. UE 335 through Commission Order No. 18-405.

[1] In PGE Exhibit 100 at page 26, PGE inadvertenly provided that PGE's waiver request was approved through Commission Order No. 17-386, which in fact is the Order acknowledging PGE's 2016 Integrated Resource Plan.

May 28, 2020

TO: Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 010
Dated May 14, 2020

Request:

Please explain why PGE is only pursuing capacity agreements with terms of five years or less.

Response:

PGE is not solely pursuing capacity agreements with terms of five years or less. During negotiations with counterparties, PGE has requested to explore longer-terms and commonly counterparties expressed no interest in executing longer duration contracts due to future uncertainties or requested that such discussions not occur until after the parties had operated under the agreement for sometime.

Page 17 through Page 38

of

Staff Exhibit 102 is confidential

Subject to

Protective Order no: 20-100

CASE: UE 377
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

June 26, 2020

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 Finance and Audit Division of the Public Utility Commission of Oregon (OPUC or Commission). 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. I discuss Portland General Electric Company's (PGE or Company) 2021 Automatic Update Tariff (AUT) filing and Staff's analysis and recommended Commission action regarding the Western Energy Imbalance Market (EIM) benefit forecast, standard inputs, and forecasted cost of wholesale transactions.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

- Staff/201: Witness Qualification Statement.
- Staff/202: PGE's responses to Staff DR Nos. 61, 73, 88, 91, and 98.
- Staff/203: Confidential Staff workpapers (electronic exhibit only).

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please summarize your recommendations and adjustments.

A. Staff's recommendations and adjustments are as follows:

1. Western Energy Imbalance Market
    a) Reject the Company's proposed forecast of sub-hourly dispatch benefits. Staff is open to supporting this forecast at a later point, if evidence is provided by the Company to support the use of the proposed trading limits, as requested on pages six and 11 of this section.
    b) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to the EIM benefits forecast, to reflect **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** accruing to the Company from flexible reserve revenue.
    c) Increase the forecasted Greenhouse Gas (GHG) benefit by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, to reflect the Company's use of California Carbon Offsets (CCO) in lieu of California Carbon Allowances for compliance purposes.
2. Wholesale Transactions
    a) No adjustments recommended.
3. Standard Inputs
    b) No adjustments recommended.

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 began participating in the EIM in late 2017. Since then, the market has expanded rapidly with the entry of Idaho Power, Powerex, part one of the Balancing Authority of Northern California, Salt River Project, and Seattle City Light. An additional five participants are expected to join the EIM in 2021, followed by eight entrants in 2022. This represents a substantial expansion to the EIM footprint, which the market operator has called "one of its largest expansion periods".[1]

As detailed by PGE in testimony, market changes introduced in late 2018 have changed the system for GHG awards.[2] The methodology used to account for this change is discussed further in Staff's testimony.

Q. How does participating in the EIM benefit PGE?

A. PGE benefits from its participation in the EIM in a number of ways:

- *Sub-Hourly Dispatch Benefits* arise due to EIM facilitating transactions between PGE, CAISO, and other EIM participants within the hour.

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1 See CAISO release "Western Energy Imbalance Market gross benefits exceed $900 million", dated April 30, 2020. Staff has reflected the recently announced delay in EIM entry for four Colorado utilities.

2 PGE/100, Niman-Kim-Batzler/13.

- *Reserve-related benefits* accrue to PGE in two ways:
  - Revenue earned by providing flexible reserves in the EIM.
  - Reduced reserve requirements on the PGE system, thanks to the diversified footprint of the EIM.
- *GHG Revenue,* which is an added price paid on all generation at a node, whenever CAISO determines that thermal generation within that node served CAISO load.

Staff will address each of the benefits listed above in turn in this section.

Q. Has PGE proposed to change its methodology for forecasting EIM benefits in the 2021 AUT?

A. Yes. The Company has proposed new mechanisms for forecasting both GHG benefits and sub-hourly dispatch benefits in the 2021 AUT. The Company did not forecast benefits from flexible reserve payments, or include reduced reserve requirements as a stand-alone forecast.

Q. Please describe the Company's proposed methodology for forecasting sub-hourly dispatch savings.

A. In its proposed model, PGE treats MONET's output as a forecasted EIM base schedule. Using a forecasted EIM price, it identifies opportunities for sub-hourly dispatch benefits, measuring those benefits as the difference between EIM prices, and either the Company's production cost (for thermal units), or opportunity cost (for hydro units). Forecasted EIM trading is limited by monthly MWh trading limits that are applied collectively to hydro units and thermal units, and which are based on average historic EIM trades.

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

A. Staff is concerned by the MWh trading limits set on forecasted EIM trading. This limit is derived from the historic average monthly sales or purchases made by the Company in the EIM in MWh, for both hydro units as a whole, and thermal units as a whole. Although Staff recognizes that there is not unlimited depth[3] available in the market, Staff is concerned that the use of the average historic value may result in lower EIM benefits than historically occur.

Figure 1 compares the Company's historic EIM trades to the limits being used in the model, showing that only **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of historic EIM sales, and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of historic EIM purchases fall within the limits.

[BEGIN CONFIDENTIAL]

Figure 1 - Distribution of instances of historic EIM purchases and sales, shown by trade size (in MWh)

[redacted]

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3 "Market depth" represents the market's ability to absorb high buying or selling without impacting the market price.

Q. What is Staff's recommendation on this issue?

A. Because of its concerns with the limitations set on EIM trading, Staff is not prepared to support the Company's proposed forecast of sub-hourly benefits at this time.

Nevertheless, Staff appreciates that the EIM market does not necessarily have enough depth to support trading at the forecasted market price, up to the maximum historic levels in each period. Similarly, modelling trades up to the maximum historic levels would not be reflective of actual operations.

Staff would like to see the Company address this issue in reply testimony, specifically addressing how EIM trades in the forecast are representative of those occurring in actual operations.

Q. The Company observes one to two percent of certain NVPC cost variables as an appropriate measure of EIM benefits, and as a measure to support its forecast of sub-hourly benefits. Does Staff support this view?

A. No, Staff rejects this perspective. The Company points to three supporting pieces of evidence for taking this stance, each of which Staff finds lacking.

- First, it references "third-party expertise".[4] Staff does not find this to be a compelling piece of evidence, as the quoted fuel costs saving does not include the optimization of hydro, and other renewable generation, which can impact the benefits received.

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[4] See the confidential attachment to PGE's response to Staff DR 85.

- Second, it points to the E3 study, which was conducted to forecast the Company's EIM benefits in the early years of its EIM participation. As has been noted in other filings, Staff finds the E3 study to be lacking. For example, it failed to forecast GHG benefits which would have provided a benefit of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to customers,[5] or flexibility reserve benefits.[6]
- Third, PGE points to past forecasts of EIM benefits being equivalent to 2.1 to 2.4 percent of the NVPC cost variables. Staff sees no value in this comparison using forecasted EIM benefits. Firstly, past forecasted values were agreed to as a matter of settlement between parties, rather than any agreement on a model. Second, actual EIM results show EIM benefits representing a much larger proportion of the identified cost variables than the forecasted values had predicted.

In Confidential Figure 2, Staff has adjusted a table from Company's filing to reflect *actual EIM benefits* as a percentage of Company's *actual fuel costs*. Further, Staff adjusted the table to reflect *2020 forecasted EIM benefits*, which had been excluded from the Company's initial filing.[7]

Staff's revised table shows support for forecasted EIM benefits equaling up to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of costs, in contrast to the Company's expectation of 1 – 2 percent.[8] Although the

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[5] See the confidential attachment to PGE's response to Staff DR 73.
[6] See Docket No. UE 333, Staff/400, Gibbens 3 – 4.
[7] See PGE/100, Table 1. Also see the confidential attachment to Staff DR 73, from which Staff sourced the addition data.
[8] See PGE/100, Seulean–Kim–Batzler/10 - 11, lines 6 – 12 and 1 – 8.

percentage difference between **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent and the 2.1 percent forecasted by the Company may appear minor, it equates to a difference in EIM benefits of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Figure 2 - PGE 100 Table 1 - Updated by Staff to reflect actual EIM results, in addition to forecasts

[BEGIN CONFIDENTIAL]

EIM Sub-hourly Dispatch Savings
Percentage of Forecast NVPC Production Costs ($million)

	Initial E3 Study	2018 NVPC Forecast	2019 NVPC Forecast	2020 AUT * Forecast	2021 AUT Forecast
EIM-Relevant Cost Variables[1]	$318.5	$228.9	$233.5	[redacted]	$195.6
PGE Sub-Hour Dispatch Saving Forecast	$3.5	$5.6	$5.0		$4.0
% of EIM-Relevant Cost Variables	1.1%	2.4%	2.1%		2.1%

Range of [redacted] equates to forecasted EIM benefit of [redacted] in 2021 AUT

Actual EIM Settlement Measurment[2]	-	$4.7	$6.3	-	-
Actual EIM-Relevant Cost Variables *		[redacted]			
% of Actual EIM-Relevant Cost Variables *					

[1]Costs in NVPC forecast are the subset of MONET costs that are variable and capable of being influenced by PGE's activity in the EIM.
[2]Settlement actuals include fifteen-minute market, real-time dispatch, and uninstructed imbalance energy EIM purchases and sales measured against the resource-by-resource production costs reported in PGE settlement data.
* Represents data added by Staff

[END CONFIDENTIAL]

Q. Does Staff have any other observations regarding the proposed sub-hourly dispatch benefits forecast?

A. Yes. Staff notes that the Company's proposed forecast does not include bid cost recovery revenue, however the reported actual benefits do.[9] Having engaged with the Company on this issue, Staff learned that bid cost recovery

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9 See PGE's response to Staff DRs 70 and 71.

revenue is intended to make generators whole when they are dispatched uneconomically by the EIM (as a result of market need). As MONET does not model uneconomic dispatches, and bid cost recovery revenue received by the Company simply covers the Company's production costs, Staff agrees with the Company's approach of not forecasting this element of EIM revenue.

Q. Moving on to reserve related benefits, Staff stated above that the Company did not forecast benefits from flexible reserve payments. What is Staff's position on this issue?

A. The Company both receives payments for providing flexible reserves, and makes payments for flexible reserves received. Historically, this has resulted in a net **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** revenue stream for the Company.

Payments associated with flexible reserves are not included in its forecast of EIM benefits, in spite of their being partially included in the Company's measure of historic EIM benefits.[10]

Staff has summarized the net value of the Company's flexible reserves payments in confidential Figure 3, showing that historically they have represented **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[11] per year to the Company.

Figure 3 - Net Flex Reserve Payment

[BEGIN CONFIDENTIAL]

[10] See PGE's response to Staff DR 73.
[11] See PGE's confidential attachment to its response to Staff DR 72.

[redacted]

[END CONFIDENTIAL]

Q. What is Staff's recommendation on this issue?

A. Staff recommends that the Commission increase the forecasted EIM benefit value by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which is calculated as the average net revenue from flex reserves in 2018 and 2019.[12]

Q. Staff also stated above that the Company did not include reduced reserve requirements as a stand-alone forecast. What is Staff's position on this issue?

A. A commonly recognized benefit of EIM participation is the need to hold lower reserves, due to the diversity benefit provided by EIM.[13] In Docket No. UE 335, PGE's 2019 AUT, PGE forecasted this to have a $1.7 million value, based on the study carried out by E3.[14]

[12] Staff has focused on 2018 and 2019 calendar year results, as these represent the only two full years of EIM operations for which data is available.

[13] As described by E3, "flexible reserve pooling uses lower reserve requirements to reflect the diversity in load shapes and solar and wind resources across the expanded EIM footprint". See Docket No. UE 335, PGE/303, Niman-Kim-Batzler/12.

[14] See Docket No. UE 335, PGE/303, Niman-Kim-Batzler/6.

Staff engaged the Company on this issue, and learned that in actual operations, the “freed-up” reserves equate to additional generation capacity available for dispatch in the EIM. The trading limits imposed in the Company’s model are intended to reflect the sale of that “freed-up” capacity.

Q. What is Staff’s recommendation on this issue?

A. As noted on page six above, because of its concerns with the limitations set on EIM trading, Staff is not prepared to support the Company’s proposed forecast of sub-hourly benefits at this time. In addition to the requested analysis on page six, Staff would like to see the Company address the issue of reduced reserve in reply testimony. Staff requests that the Company specifically address how its forecast reflects the use of “freed-up” capacity, and how this compares to the diversity benefits calculated by the CAISO.

Q. Explain how the Company has proposed to forecast GHG revenues in the 2021 AUT.

A. The Company’s proposed model relies on actual EIM results for the period beginning January 2019. By focusing on the period post-November 2018, the forecast draws in the Company’s most recent results, reflecting changes made by CAISO to the GHG market in EIM in November 2018.

The Company’s creates both a GHG revenue forecast and GHG compliance cost forecast by adjusting past EIM results for 2021 forecasted California Carbon Allowance (CCA) prices. The forecasted GHG benefit equates to the forecasted GHG revenue less forecasted GHG compliance costs.

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

A. Yes. Staff notes that the Company has historically used California Carbon Offsets[15] (CCO) to comply with its CARB GHG emissions requirement.[16] The Company purchases the CCOs in the over-the-counter market, where these instruments typically trade at a discount of 10 to 25 percent of the CCA price.[17]

Staff discovered that the Company **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

As noted above, the Company's proposed model forecasts GHG benefit as the forecasted GHG revenue received from CAISO, less forecasted CARB compliance costs. The Company uses GHG bids, based on CCA prices alone, as the foundation of its CARB compliance cost. Consequently, any savings arising from the use of CCOs for CARB compliance are not passed through to customers.

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[15] California's Cap-and-Trade program allows the use of GHG reducing offset projects to meet CARB GHG compliance obligations. For PGE, this has included CCOs **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** See the confidential electronic attachment to PGE's response to Staff DR 61.

[16] See PGE's response to Staff DR 61.

[17] See PGE's response to Staff DR 61.

[18] Staff has focused on 2018 and 2019 CARB compliance, as this represents two full years of trading in EIM. The **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**.

[19] See the confidential attachment to PGE's response to Staff DR 61. Note that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What is Staff's recommendation?

A. Staff recommends that the Company adjust its calculation of GHG benefits to account the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** typically achieved by using CCOs for CARB compliance. In addition to passing through benefits to customers more accurately, this approach would provide consistency with the Company's measurement of EIM benefits for thermal units, in which the procurement cost of fuels is used, rather than the bid cost.

The adjustment proposed by Staff on this issue represents a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to NVPC.

Q. Are any outstanding issues relating to the Company's forecast of GHG revenues?

A. Yes. One issue, relating to GHG award activity in EIM, remains outstanding. In the Company's testimony it states:

> *PGE will monitor the GHG award activity after Seattle City Light joins on April 1, 2020. If there is a noticeable change in the market, PGE intends to reflect the change through a revision to the implied emission factor ... The change would reduce the GHG benefit from $3.0 million to $1.9 million.*[20]

Staff queried this issue with the Company and learned that there were no noticeable changes in GHG shadow prices or average implied emission rates when comparing April and May on a year-over-year basis (e.g., April 2020 vs.

[20] PGE/100 Seulean–Kim–Batzler/15 and /16, lines 17 – 21 and 1 – 2.

April 2019), to support a change in the implied emission factor used in the Company's initial filing.[21]

Q. How does Staff plan to proceed?

A. Staff has requested through discovery that the Company provide monthly updates on this matter. Both Staff and the Company intend to continue to monitor the issue during the course of this proceeding.[22]

Q. Does Staff have any other observations regarding the total EIM benefit forecast?

A. Yes. A final outstanding issue is the addition of the Douglas PPA, described in the Company's supplemental filing on May 15, 2020.

In its filing the Company noted that the current power cost impact estimate was "based on February 28, 2020 forward price curves and does not incorporate any adjustments to the EIM benefits to account for the addition of the Douglas PPA".[23]

Staff will continue to monitor this issue, and respond to the Company's proposed adjustments in later filings.

Q. Would Staff advocate for any of the proposed EIM benefit forecasting methods to be used in coming years?

A. No. Given that the Company has not yet completed three full years in the EIM, and has limited actual data available, Staff is not prepared to agree on an enduring model for EIM benefits.

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[21] See PGE's response to Staff DR 88.
[22] See PGE's response to Staff DR 88.
[23] See PGE/300, Seulean–Kim–Batzler/11, footnote 12.

Q. Has Staff reviewed the Company's forecasted EIM costs?

A. Yes. Staff reviewed the Company's forecasted EIM costs, and found no issues.

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 $7.9 million in 2021, compared with its 2020 forecast. The Company has attributed the majority of this increase to new capacity agreements, while $2.6 million of the increase can be attributed to increased load.[24]

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

A. Staff investigated the overall costs and revenues associates with the Company's wholesale purchases and sales. Staff also focused on the procedures and policies the Company has in place for risk management, hedging, and trading. Staff identified no issues.

Q. Does Staff have a recommended adjustment regarding this issue?

A. No.

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[24] PGE/100, Seulean–Kim–Batzler/44.

ISSUE 3. STANDARD INPUTS

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

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 by Staff in this filing include forecasted derations, forced, and schedules outages; forecasted integration costs, royalties, generation capacities, and other costs for wind generators; forecasted generation capacities, heat rates, and O&M for thermal units; along with gas and electric forward curves.

Q. Please provide an overview of Staff's analysis.

A. Staff performed extensive discovery on these issues. Staff investigated the Company's forecasting methodology, and looked at the results of its past forecasts, by comparing five years' worth of actual values against forecasts for those same years. Staff identified no issues.

Q. Does Staff have a recommended adjustment regarding this issue?

A. No.

Q. Do the standard inputs used in the Company's filing comply with the terms agreed in Order No. 19-329?

A. Yes. Order No. 19-329 required that the Company use "the inflation rate modeled in PGE's most recently acknowledged Integrated Resource Plan for future annual power cost proceedings."[25] The Company complied with this

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[25] See Order No. 19-329, Appendix A, page 4.

requirement in its April 1 initial filing,[26] and has informed Staff that it will update this rate with the inflation rate from its 2019 IRP, which has since been acknowledged by the Commission, in an upcoming future MONET update.[27]

Order No. 19-329 also required that the Company "round thermal plant forced outage rates to the nearest two decimal places".[28] Staff has verified that this approach was used by the Company in its 2021 AUT filing.[29] Furthermore, the filing complies with the requirements for the Minimum Filing Requirements (MFR) for the Company's AUT filings, as detailed in Order No. 08-505.

Q. Does this conclude your testimony?

A. Yes.

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[26] PGE used the inflation rate from its 2016 Integrated Resource Plan in the April 1 initial filing (the most recent IRP acknowledged by the Commission at the time).
[27] See the Company's response to Staff DR 91.
[28] See Order No. 19-329, Appendix A, page 4.
[29] See the Company's response to Staff DR 91.

CASE: UE 377
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 26, 2020

WITNESS QUALIFICATIONS STATEMENT

NAME:	Moya Enright
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates Finance and Audit 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:	I have been employed as a Senior Utility and Energy Analyst at OPUC since January 2019. My current responsibilities include financial analysis, with an emphasis on Cost of Capital (CoC) and power cost forecasting. I have worked on CoC in the following general rate case dockets: AVA UG 366 and pending NWN UG 388; AVA UG 389; CNG UG 390. Prior to joining OPUC I was employed as an Energy Trader for Meridian Energy, a hydro and wind energy generator in New Zealand from 2015 to 2019; as a Trading and Operations Analyst at Tynagh Energy, a gas focused independent power producer Ireland from 2011 to 2013; as a Senior Electricity Market Controller at EirGrid, the Irish Transmission System Operator from 2008 to 2011; and in various Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG.

CASE: UE 377
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 26, 2020

June 5, 2020

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 061
Dated May 22, 2020

Request:

Regarding the use of offsets in the Company's CARB compliance:

a. Please indicate whether the Company used offsets in its CARB compliance since joining the EIM.

b. If yes to section "a", please detail the value of the offsets to the Company in dollars.

c. If yes to section "a", please detail the value of the offsets to the Company in avoided CCAs.

d. If yes to section "a", please provide details of the offset projects.

e. If yes to section "a", please provide details of the cost to the Company in participating in the offset projects.

f. The quantity and total dollar value of offsets "banked" by the Company on December 31, 2019. Include an explanation of what proportion of the banked offsets are intended for use during the 2021 test year.

Response:

a. Yes, PGE used offsets in its CARB compliance since joining EIM.

b. Attachment 061-A provides the value of the carbon offsets PGE used in its CARB compliance and details about the projects generating those offsets.

c. PGE objects to this request on the basis that it is overly broad and calls for speculation. Without waiving and notwithstanding this objection PGE responds as follows:

   Depending on the quality of the carbon offsets, they trade between 75% and 90% of the carbon allowance price.

   Due to the CARB Carbon Offset Rules, new carbon offset projects carry eight years of invalidation risk from credit issuance. As a result, carbon offsets from these projects (i.e. CCO8's) carry eight years of invalidation risk and trade at the largest discount to carbon allowances. Carbon offsets generated by carbon offset projects that have zero years of invalidation risk (CCO Zeros) left trade at the smallest discount to CCAs. Carbon offsets also trade as a "Golden" product, for which the invalidation risk is transferred to another party in contracting. The contracting party will replace an invalidated product with a valid carbon offset or carbon allowance.

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

e. PGE is not an owner or partner in the offset project. We buy carbon offsets in the over-the-counter market.

f. PGE objects to this request on the basis that it calls for speculation. Without waiving and notwithstanding this objection PGE responds as follows:

   Please see PGE's response to part (b) for the carbon offsets PGE currently has available. At this time PGE's 2019 CCA compliance obligation is still to be approved by the California Air Resource Board (CARB) and PGE does not currently have sufficient information regarding its CCA compliance obligation in 2020. PGE's CCA compliance obligation is contingent upon PGE's trading volumes in the spot market which makes it difficult to forecast the carbon offset bank balance at the end of 2020. As such, PGE cannot accurately project the proportion of banked carbon offsets to be used during 2021.

UE 377

Attachment 061-A

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

Carbon Offsets Used By PGE
2017-2019

June 10, 2020

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 073
Dated May 22, 2020

Request:

See attachment "PGE UE 377 OPUC 73 Attachment A ME", which summarizes the data shown at PGE/100, Seulean–Kim–Batzler / 11, Table 2.

a. Please complete the highlighted cells C7 to G16 and C20 to N22. **Note:** This is an ongoing request, please update this response as new data for 2020 becomes available.

b. Please provide a breakdown all of "EIM-Relevant Cost Variables" for the 2021 test year in electronic workbook format, with all cells and formulas intact. Include the name of the variable, and the forecasted dollar value.

c. Please indicate whether the value "Actual EIM Settlement Measurement" includes each of the following EIM benefits:

   i. GHG benefits.

   ii. Flex reserve benefits.

   iii. Energy transfer/Sub-hourly dispatch benefits.

Response:

a. See confidential Attachment 073-A.

b. See Attachment 073-A. Worksheets titled "…_PwrCsOut_Forecast" identify "EIM-Relevant Cost Variables." Effectively, the relevant cost variables are fuel costs for PGE's thermal resources, and market purchases used by MONET to serve load.

c.

   i. No. PGE measured GHG revenues and costs separately from sub-hourly dispatch savings and the actual EIM settlement data used to measure the sub-hourly dispatch savings (i.e., Actual EIM Settlement Measurement).

ii. Partially. It includes all flexible ramping product revenue, but it does not include flexible ramping product charges. See PGE's Response to OPUC Data Request Nos. 072 and 086.

iii. Yes.

Attachment 073-A is protected information subject to Protective Order No. 20-100.

UE 377

Attachment 073-A

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

PGE Exhibit 100 – Table 2 Detailed Information

June 5, 2020

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 088
Dated May 22, 2020

Request:

PGE/100, Seulean–Kim–Batzler/14, lines 17 – 19 state "PGE will monitor the GHG award activity after Seattle City Light joins on April 1, 2020. If there is a noticeable change in the market, PGE intends to reflect the change through a revision to the implied emission factor." **Note:** This is an ongoing request, please provide an updated response on a monthly basis going forward.

a. Please provide a narrative explanation of any changes observed to date.
b. Please provide data to support PGE's response to section "a".
c. Please indicate whether PGE intends to revise the implied emissions factor based on the observed changes.

Response:

a. Seattle City Light joined the EIM on April 1, 2020. Comparing the months of April and May on a year-over-year basis (e.g., April 2020 vs. April 2019), there are currently no noticeable changes in GHG shadow prices or average implied emission rates.
b. Attachment 088-A compares the GHG shadow prices, GHG allowance prices and average implied emission rates used to support PGE's response to part a.
c. To-date, the April and May observations would support no change to PGE's implied emission factor in the GHG benefit forecast method proposed in its Initial Filing. PGE will continue to monitor GHG market data in June and July.

UE 377

Attachment 088-A

Provided in Electronic Format

GHG shadow prices, GHG allowance prices, and average implied emission rates

June 5, 2020

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 091
Dated May 22, 2020

Request:

Appendix A to Order No. 19-329 states that "the Stipulating Parties further agree that PGE will use the inflation rate modeled in PGE's most recently acknowledged Integrated Resource Plan for future annual power cost proceedings."

a. Please indicate whether PGE has taken this approach in its 2021 forecast.

b. If no to section "a", please provide a reason for this.

Response:

a. Yes, for the 2021 AUT April 1 initial filing, PGE used the inflation rate modeled in PGE's 2016 Integrated Resource Plan (IRP) which was the most recent IRP acknowledged by the Commission at that time. Subsequently, on May 6, 2020, the Commission issued Order 20-152 acknowledging PGE's 2019 IRP. PGE will update the inflation rate in a future MONET update to reflect the inflation rate in the 2019 IRP.

b. N/A

June 23, 2020

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 099
Dated June 4, 2020

Request:

With regard to the purchase of CCOs:

a. Please list PGE's CCO purchases since joining the EIM in electronic spreadsheet format with all formulas and cell references intact. For each transaction, include the cost in dollars, credits purchased, and purchase price.

b. Please provide a narrative explanation of how PGE purchases CCOs, including details of how the Company limits its exposure to invalidation risk, and ensures that the most advantageous price is achieved.

Response:

a. Please see Attachment 099-A.

b. Please see PGE's response to OPUC Data Request No. 061 describing the types of CCO products and their invalidation risk. To limit the exposure to invalidation risk PGE is only transacting CCO Zeros or "Golden" CCOs, which have no invalidation risk, or the invalidation risk is transferred to another party in contracting, respectively. To ensure PGE achieves the most advantageous prices in CCO trading, PGE actively evaluates and monitors the secondary market through the Intercontinental Exchange (ICE), Broker Quotes, Bilateral trades while also monitoring policy changes that could fundamentally shift supply of offsets.

Attachment 099-A is protected information subject to Protective Order No. 20-100.

UE 377

Attachment 099-A

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

CCO Transactions
October 2017 - Present

CASE: UE 377
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

Non-Confidential
June 26, 2020

Staff Exhibit 203 is confidential

And filed in electronic format

Subject to

Protective Order No: 20-100

CASE: UE 377
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

REDACTED

June 26, 2020

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

A. My name is Scott Gibbens. I am a Senior Economist 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/301.

Q. What is the purpose of your testimony?

A. I discuss the 2021 AUT filing and Staff's review of and recommended Commission action regarding: 2021 transmission rights, Wheatridge Renewable Energy Facility (Wheatridge), and the Company's load forecast.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/302, PGE Response to CUB DR No. 4. As well as confidential Exhibit Staff/303, PGE Response to AWEC DR No.10.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. 2021 TRANSMISSION RIGHTS

Q. Please describe this issue.

A. PGE is proposing an increase in transmission costs of approximately $14 million in 2021 compared to the current amount in rates. PGE reports this is due to several factors: transmission costs related to the Wheatridge Renewable Energy Facility (Wheatridge), expiration of BPA point-to-point (PTP) transmission credits associated with PGE's Tucannon wind farm, and Bonneville Power Administration (BPA)'s bi-annual rate case that is expected to raise transmission rates. This is further complicated by the closure of the Boardman coal plant in 2020.

Q. Does the Company provide evidentiary support for the increase in transmission related costs?

A. Yes, the Company does address the need to provide transmission related to Wheatridge, an explanation of the Tucannon credit expiration, and overall increase related to the expected BPA rate case increase in testimony and provided workpapers. The Company further notes that although the Boardman plant reduced transmission needs from a particular point in its transmission system, it did not reduce the overall load required by the Company to serve.

Q. How is PGE managing its transmission costs in response to the closure of Boardman?

A. PGE only broadly addressed the closure of Boardman as it relates to transmission in opening testimony, and Staff hopes that the Company will further expound on the issue in reply. However the Company's workpapers provide every transmission contract associated with the Slatt Substation (Slatt) point of receipt (POR), which is where both Boardman and Carty are located. PGE has **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of transmission capacity set to expire in 2021. Further, in discovery PGE stated that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of transmission rights expired in 2019.[1] This seems somewhat in line with the 550 MW nameplate capacity of Boardman. However, PGE noted that 100 MW of BPA PTP transmission rights at Slatt became active in May 2020, resulting in an increase of approximately $0.7 million in NVPC.

Q. Does Staff have any recommended adjustments to transmission costs?

A. Not at this time. Staff notes that transmission planning is a multi-year process with a horizon that extends much longer than the 2021 AUT test year. Staff agrees with the Company that matching transmission rights exactly to transmission needs is a difficult task that may not be possible when looking at a one-year horizon. As such, annual power cost filings are a difficult venue to determine prudence; however, this issue represents a relatively large increase which warrants a full and thorough review. Staff has concerns regarding the amount of transmission rights currently owned out of Slatt, the amount of transmission rights the Company has to Mid-C, and the Company's transmission planning policy for opt-out customers in light of the pending issue in UM 2024. Staff continues to review the Company's proposal in light of its forecasted needs in this test year as well as future needs beyond. Beyond any

[1] See Confidential Staff/303, PGE's response to AWEC DR No. 10.

recommendations or changes that ultimately result from this filing, Staff recommends that the Company consider these concerns in its next IRP and any transmission focused docket which may be filed in the next few years.

ISSUE 2. WHEATRIDGE

Q. Please describe the Wheatridge Renewable Energy Facility.

A. Wheatridge is a 300 MW wind, 50 MW solar, and 30 MW four-hour duration energy storage facility located in Morrow County, Oregon. The wind facility is scheduled to come online in the 4th quarter of 2020, while the solar and battery storage portions are scheduled to come online at the end of 2021. PGE has forecast the NVPC benefits of the wind facility into this year's AUT. This includes 100 MW, which PGE will own, and a 200 MW long-term PPA. The wind project is expected to provide a net dispatch benefit of $3.5 million. This includes a $14.8 million power cost reduction for the PGE-owned portion and $11.3 million cost for the PPA.

Q. How does PGE propose to forecast the energy output from Wheatridge?

A. PGE proposes to use the standard forecast methodology for its wind generating facilities in the AUT. This is a five-year moving average forecast that utilizes the P50 forecast included in the RFP scoring process for any year where actual historical data is unavailable. Being that this is the first year of operation, the entire forecast is based on the P50 forecast.

Q. Does Staff agree with this methodology?

A. No. Staff believes that the circumstances surrounding the investment decision warrant a modified methodology for capacity factor calculation. However, Staff's recommended approach and PGE's proposed approach would result in no difference for this year's AUT as they would both rely fully on the P50 forecast for the methodology. Further, Staff entered into a stipulated agreement in last year's AUT proceeding by which all parties agreed to refrain from proposed changes to capacity factor calculations until the Company's next general rate case. Given these two factors, Staff recommends no change to the Company's proposed methodology for Wheatridge capacity factor calculation at this time.

Q. Why does Staff believe that an alternative approach may be reasonable in the future?

A. Staff believes that the risk sharing between shareholders and customers needs special attention when the Company makes investment purchases beyond what is strictly needed for serving load. This was the case in PacifiCorp's EV 2020 investment and parties and the Commission ultimately decided upon a unique treatment for capacity factors in PacifiCorp's 2019 and 2020 TAM. Staff has already outlined some of its concerns in UE 370, PGE's Renewable Adjustment Clause, which is designed to provide the Company with cost recovery outside of a general rate case for renewable energy investments. As Staff is not making any recommended changes in this filing, Staff's goal is only to signal to the Company and the Commission that it believes that the methodology should be reconsidered in the Company's next general rate case.

Q. Are there any potential changes to the way that Wheatridge is modeled?

A. Yes. Wheatridge is located in BPA's balancing authority area (BAA) and as such is being balanced by BPA. This requires PGE to purchase Variable Energy Resource Balancing Services (VERBS) from BPA for the output of

Wheatridge. PGE is currently in the process of "pseudo-tying"[2] the project output so that PGE can self-integrate the resource. This allows the Company to avoid the VERBS fee. PGE notes in its initial application that if the Company is able to clarify a pseudo-tie date, it will update the AUT filing.

Q. What is VERBS?

A. VERBS is a Control Area Service offered by BPA to all Variable Energy Resources (VERs) that are within BPA's BAA in order for the VERs to satisfy its reliability obligation. Wheatridge will provide a variable amount of power at any given moment based on wind speed and direction. BPA offers utilities the option to select a VERBs product to balance the variable energy at four different levels based on the frequency of energy schedules submitted and the generation signal persistence used to calculate the schedules. The products currently offered are referred to as "30/60," "30/15," and "Uncommitted," where the first number is the number of minutes preceding the scheduling period for which the persistence value (one-minute average of the actual generation) is calculated, and the second number is the length of the scheduling period. Under the Uncommitted Scheduling, a party can either 1) use the BPA supplied wind generation forecast as the schedule, or 2) they can opt to use a different forecast for an additional fee.

[2] A pseudo-tie is a time-varying energy transfer that is updated in real-time allowing the generator of a Balancing Authority Area (BAA) to physically reside outside the contiguous boundaries of the BAA.

Q. Does Staff have any recommendations regarding the Company's proposal for balancing services?

A. No. PGE has selected the cheapest VERBs option to include in rates and Staff finds the decision necessary and prudent. Staff only asks that if the Company is able to identify a date which the pseudo-tie will be complete, that the Company incorporate any potential changes in EIM benefits into its update. Staff's understanding is that there may be implications for the Company's ability to bid a resource outside of its BAA into the EIM, which would be mitigated if Wheatridge were to move into PGE's BAA. As such, Staff believes that the Company should account for this in its update if applicable.

ISSUE 3. LOAD FORECAST

Q. What is PGE's load forecast for 2021 retail load?

A. PGE's initial 2021 retail load forecast is 19,717 GWh.[3] This is approximately a 0.5 percent increase from forecasted 2020 deliveries in last year's AUT.

Q. What are the primary drivers of the increase in load in the 2021 AUT?

A. The forecasted increase in total load is due to increases in the Industrial customer class loads."[4]

Q. How did Staff analyze this issue?

A. Staff reviewed the Company's workpapers related to load forecast to ensure proper calculation of the model. 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

[3] PGE/100, Seulean et al./40.
[4] *Ibid*.

review of the Company's forecast is performed. As PGE noted in response to CUB DR No. 4, the Company has utilized the same load forecast model as UE 335, with the inputs updated to include the most recent projections.[5]

Q. Has PGE incorporated the impacts of COVID-19 in its forecast?

A. No. PGE notes that as of the time of the filing, the extent of the impacts of the pandemic were largely unknown. Staff notes that the Oregon Department of Economic Analysis, whose forecast is utilized by PGE in its modeling, has revised its 2021 unemployment forecast from approximately 4 percent in 2021 to nearly 15 percent.[6] Personal income has likewise seen a drop from roughly nine percent growth from 2019-2021 to only 1.2 percent.[7]

Q. Does Staff propose an adjustment to Load Forecasting?

A. No. Not at this time. Staff has reviewed the Company's inputs and methodology and finds no errors. Given the unknown and potentially significant impacts of COVID-19 on load demand, Staff will continue to review as the Company updates its load forecast inputs to include any updated forecast that incorporates the impacts of the pandemic.

Q. Does this conclude your testimony?

A. Yes.

[5] See Staff/302, PGE's response to CUB DR No. 4.
[6] See https://www.oregon.gov/das/OEA/Documents/forecast0620.pdf, page 15.
[7] *Ibid.*

CASE: UE 377
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 26, 2020

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 have been the power cost team manager since January 2017. I have worked on the following power cost dockets: PAC UE 307, UE 309, UE 323, UE 327, UE 339, UE 344, UE 356, UE 361, and current UE 375 and UE 379. PGE UE 308, UE 310, UE 319, UE 329, UE 335, UE 346, UE 359, UE 362, and current UE 377. IPC UE 301, 305, UE 314, UE 320, UE 333, UE 336, UE 350, UE 354, UE 366, and current UE 376. I've also performed analysis and review on a variety of other issues at the Commission. I have reviewed issues and made recommendations to the Commission in the following general rate cases: AVA UG 325, UG 366 and current UG 389; NWN UG 344, and current UG 388; PAC current UE 374; PGE UE 319, and UE 335; and CNG UG 305, UG 347 and current UG 390. 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 377
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 26, 2020

June 12, 2020

TO: William Gehrke
Oregon Citizens' Utility Board

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to CUB Data Request No. 004
Dated May 29, 2020

Request:

Refer to UE 377 – PGE/100/ Seulean – Kim – Batzler /Pages 42, Lines 7-11. On what interval (annually, monthly, quarterly, prior to MONET updates, etc.), does PGE update the inputs to the load forecast model used to generate its 2021 test year power cost forecast? CUB understands that the same forecast models are used in UE 377 to forecast load in the 2021 test year that were used in UE 359.

Response:

PGE's load forecast is updated several times each year, at which time updated inputs are included. PGE's prompt year internal budget process begins with a September load forecast, and the need to update the load forecast is assessed on a quarterly basis thereafter. A number of criteria are used to make this assessment including changes in economic forecast inputs, changes to large customer expectations and variance analysis of recent results. Methodological changes to the forecast model are included during a General Rate Case Filing, as such, the load forecast model used for UE 359 and UE 377 are consistent with that used in UE 335. However, the final forecast output used in UE 359 was based on the September 2019 forecast vintage whereas the initial filing for UE 377 was based on the March 2020 forecast vintage.

CASE: UE 377
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

Non-Confidential
June 26, 2020

Staff Exhibit 303 is confidential

Subject to

Protective Order no: 20-100

CASE: UE 377
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 26, 2020

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. I discuss my analysis and recommendations for Qualifying Facilities purchased power costs as proposed by Portland General Electric (PGE)'s 2021 Annual Update Tariff (AUT) filing, Docket No. UE 377.

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. 17, 18, 20, 21, 92 and 93
- Staff/403: PGE's Confidential Response to Staff Data Request No. 17a and 92a.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please summarize your testimony.

A. In Addition to PGE' s derate adjustment of essentially projected newly operating QF of $24.5 million,[1] I have an adjustment of **[Begin Confidential]** [redacted] **[End Confidential]**, representing an over-forecast of existing QF purchased power costs. Using the PGE power costs model run QF purchased power costs estimate of **[Begin Confidential]** [redacted] **[End Confidential]**, and subtracting PGE's derate adjustment of $24.5 million, as well as my QF operating adjustment of **[Begin Confidential]** [redacted] **[End Confidential]**, we get a QF projected QF purchased power cost of **[Begin Confidential]** [redacted] **[End Confidential]**.

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1 See PGE/100, S-K-B/30, lines 7-9

ISSUE 1. QUALIFYING FACILITIES

Q. Please discuss Qualifying Facilities (QF) and how the costs are treated in the AUT.

A. Costs for purchases from new QFs can be difficult to forecast accurately because it is not unusual for a QF to miss its scheduled commercial on-line date (COD). To address this issue, parties to PGE's 2017 general rate case stipulated to a track and true-up mechanism to separately track costs for new QFs within the AUT, which the Commission approved in Order No. 18-405. Under Order No. 18-405, PGE updates QF commercial on-line dates through the final MONET update. PGE then tracks the on-line dates for new QFs and defers the difference between actual and forecasted QF costs to recover or credit the variance related to changed CODs in the next power cost proceeding.[2]

In PGE's subsequent AUT filing in 2018, the parties stipulated to a modification of the track and true-up mechanism requiring PGE instead to derate the expected generation of new QFs that have not achieved commercial operation by November 1 of the year preceding the test year, and to make reasonable efforts to update any known changes to QF commercial operation dates between November 2 and the final November MONET update.[3] The energy derate is based on the most recent four-year historical average of actual versus projected QF costs.[4]

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[2] OPUC Order No. 18-405, App. A, pp. 2-3.
[3] OPUC Order No. 19-329, APP A, p. 3.
[4] Id.

Q. Please discuss PGE's projection of QF costs for this AUT.

A. As part of PGE's projection of QF costs, PGE developed a forecast of the cost of purchasing power from new QFs projected to come on-line in 2020 and 2021. PGE's Response to Staff Data Requests No.17,18, 20, and 21, which are attached as Exhibit Staff/402, all relate to PGE's treatment of new QFs projected to come on line between now and through the 2021 test year. The total projected costs of purchases from new QFs for the 2021 test year is **[Begin Confidential]** [redacted] **[End Confidential]**.[5]

PGE then derated new QFs that have not achieved commercial operation based on the most recent four-year historical average of actual versus projected QF costs.

Q. For the four-year average calculation of the derate percentage for QFs without commercial operation dates what did PGE calculate?

A. The derate value is 83 percent and Staff supports that derate value.[6]

Q. Did PGE apply the 83 percent to the new QFs projected to come on line that have not yet achieved commercial operation?

A. Yes. PGE applied the 83 percent deration for the four new QFs projected to come on line in 2021 and the QFs projected to come on line in 2020 that have not reached commercial operation.[7] There are 29 such QFs.

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[5] From the April MFR, the 2021 power cost output associated with the steps in the step log is provided in the folder Confidential/Output in that folder include the 2021 projected costs associated with each QF contract in the worksheet "PwrCsOut' starting at row 73.

[6] PGE/100, S-K-B/28, lines 17-19.

[7] See response to Staff Data Request No.22, attached as Exhibit Staff/402 from the 4 and 29 values.

Q. What is PGE's total adjustment to purchased power costs associated with the QF derate?

A. It is $24.5 million.[8] Staff appreciates PGE's efforts in addressing the derate issue for this docket and how they have applied the Stipulation and its terms reached in the prior rate case.

Q. Given this derate value of $24.5 million, what is PGE actually requesting for QF-related purchased power costs?

A. The answer, inclusive of the deration adjustment, equals the power costs QF purchased power costs 2021 value of **[Begin Confidential]** [redacted] **[End Confidential]** minus $24.5 million or **[Begin Confidential]** [redacted] **[End Confidential]**.

Q. Does Staff have any concerns with PGE's forecast QF purchased power costs given the deration adjustment implementation for new QFs?

A. Yes. Resolving the deration adjustment deals with QFs not yet achieving commercial operation, but there remains a concern regarding the forecasts of purchased power costs from operating QFs, that is those QFs that have been in commercial operation in the year prior to the test period. For the purpose of this discussion, Staff will focus on QFs that are in operation even a year before that. Thus, given that this a 2021 test period, we would focus on those QFs that were in commercial operation in or before the end of 2019.

Q. Did you look at the relationship of PGE projected to actuals for QFs that have been in commercial operation on or before 2019?

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[8] See PGE/100, S-K-B/30, lines 7-9.

A. Yes. The table below shows a comparison of actual to projected QF purchased power costs for all QFs that have operated in years prior to and up to the end of 2019, and therefore have reached its commercial operation date no later than two years prior to the forecasted test year. Many of those QF had commercial operation dates prior to 2019.

Table 1 Data Related to QFs Operating as of 12/31/2019

[Begin Confidential]

Years	2016	2017	2018	2019	2021 Projected Total
Projected QFs Power Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Actual new QF's Power costs	[redacted]	[redacted]	[redacted]	[redacted]	
Projected QFs MWH	[redacted]	[redacted]	[redacted]	[redacted]	
Actual QFs MWH	[redacted]	[redacted]	[redacted]	[redacted]	
% QFs power purchased cost actual vs projected	[redacted]	[redacted]	[redacted]	[redacted]	
% MHW actual vs projected	[redacted]	[redacted]	[redacted]	[redacted]	

[End Confidential]

Q. What do you conclude from that table?

A. It is clear that even for operating QFs, PGE is significantly over-forecasting purchased power costs from its QFs for 2019. In 2019, PGE had purchased power costs from its operating QFs in the amount of **[Begin Confidential]** [redacted] **[End Confidential]** and yet PGE is forecasting **[Begin Confidential]** [redacted] **[End Confidential]** in QF purchased power costs from these QFs in 2021. Even if you took the maximum purchased power cost from each operating QF from the time frame of 2016 through 2019, the total actual purchased power cost is **[Begin Confidential]** [redacted] **[End**

Confidential], which is still far below the PGE projected power costs for these operating QFs.

Q. What could be the sources of over-forecasting of purchased power costs from QFs that had a commercial operation date no later than the end of 2019?

A. I believe PGE's response to staff Data Request 93 provides an indication as to the basis of the over forecasting. The relevant portion of the data request states the following:

> *As provided in PGE's response to OPUC Data Request N.023, PGE is forecasting the QF generation based on information provided in the executed Schedule 201 or 202 QF agreements. The QF agreements provide expected commercial operation dates and in most cases, also provide information regarding the facility projected generation. If the agreement does not include projected generation PGE would use generation data from a proxy resource.*

I read this response to say that PGE projects the power costs from a QF to be based on the power purchased contract and therefore not from actual operation. If you wanted to forecast the maximum possible power cost from QF, you would look at the power purchase contract. But presumably the QF does not operate always at "full" capacity. Because PGE does not look at previous actual production from the QF but looks at only the contracted amounts, a clear outcome of this approach is to have forecast that overstates expected QF purchased power cost. A more reasonable approach is to inform the power purchase contract amounts by actual production. After all, how a QF performs is really what matters and what PGE paid for, not the contracted maximum amounts.

Q. Does the table above reflect PGE forecasting the contracted amounts as described in the response to data request?

A. That is unclear. In some years, PGE's actual QF purchased power costs are above forecasted, which would mean the QF exceeding its contractual amounts. In other years, actual QF purchased power exceeds the forecasted amount. It is true that the relationship of MWh and power costs between forecasted and actual track together meaning that is MWh are over forecasted then power costs is as well for that year. The fact that the percentage over forecasting or under-forecasting is not the same for power costs and MWh is not a substantive concern because the values reflect an aggregation of contracts that have different contract terms.

Q. Based on this information, does Staff recommend an adjustment?

A. Yes, Even if we take the maximum value of actual purchased power QF costs of **[Begin Confidential]** [redacted] **[End Confidential]** and we increase it by 17.1 percent a year for two years (going from 2019 to 2021) for escalation purposes, we get a value of **[Begin Confidential]** [redacted] **[End Confidential]**. Subtracting that value from PGE's projected 2021 QF purchased power cost we get a value of **[Begin Confidential]** [redacted] **[End Confidential]**. That is my adjustment to QF purchased power cost that is in addition to PGE's derate adjustment of $24.5 million. That means from the PGE power costs model run QF purchased power cost estimate of **[Begin Confidential]** [redacted] **[End Confidential]**, and subtracting PGE's derate adjustment of $24.5 million as well as my QF operating adjustment of **[Begin**

Confidential] [redacted] **[End Confidential]**, we get QF purchased power costs of **[Begin Confidential]** [redacted] **[End Confidential].**

Q. How did you get the escalation value of 17.1 percent per year?

A. The 17.1 percent value was derived by taking the percentage increase in the total QF purchased power costs from 2018 to 2019 for the QFs that operated in both 2018 and 2019. That approach seemed a reasonable proxy for escalating 2019 QF purchased power costs to 2021 for the QFs that were operating in 2019.

Q. Could you please summarize your adjustment?

A. Yes. Staff recommends and additional adjustment of **[Begin Confidential]** [redacted] **[End Confidential]** in addition to PGE's derate adjustment. Staff is also proposing that PGE change its forecasting approach for operating QFs to base costs principally by actual operating history when available. While it is understandable that PGE may consider maximum potential obligation to purchase as a forecasting approach, clearly existing QFs are not operating at their contract potentials but less than that amount.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 377
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

June 26, 2020

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 (OPUC) 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:

I spent six years as a 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, and working as or with anExpert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst.

I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

I have served as a Principal Analyst at the OPUC for the determination of Energy Property Sales (Oregon Revised Statute 757.140) for the past 3 years. In this position, I investigated, analyzed, and calculated energy cost and impact.

<u>I also support work related to power costs,</u> plant, and associated impact on customer rates. I have reviewed, calculated, and analyzed QFs, wheeling, forced outage rates and Scheduled maintenance outages, PURPA, Solar forecast, wind forecast (UE 366).

I has worked on power cost issues in the below representative cases:

1. UE 366 Idaho Power.
2. UE 375 PacifiCorp
3. UE 377 Portland General Electric PGE

I generally conduct case investigation and analysis on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are:

- PacifiCorp
- PGE
- Northwest Natural Gas
- Idaho Power
- Avista Corp
- Cascade Gas

<u>General Rate Cases</u>: I have been a part of <u>almost every energy rate case</u> since I joined the Oregon PUC in 2016. Historically, my review has included, property sales, material and supply, donations, marketing cost. Currently, my review includes property sales and low-income issues. My work is generally represented in the last four General Rate cases, as examples:

- UG 388 NW Natural
- UE 374 Pacificorp
- UG 389 Avista
- UG 390 Cascade

<u>Rulemaking</u>: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

<u>Low-Income:</u> Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 2058.

<u>Auditing, Interest Rate, Affiliated Interest</u>: I audited cost of capital and financial components (IU 437)

CASE: UE 377
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

June 26, 2020

UE 377/PGE
OPUC Data Request 17

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 017
Dated May 15, 2020

Request:

For each of the QF contracts projected to come on line in 2020, please provide the following by month for each month of 2021.

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 017-A provides the requested information for QF contracts projected to come online in 2020. The kWh and costs provided for items (b) and (d) reflect the updated QF energy derate for the 2021 AUT in Step 0b of approximately 83%.

a) The number of kW projected to be supplied in 2021 by each QF projected to come on line in 2020 is provided in Attachment 001-A, column R.

b) The number of kWh projected to be supplied monthly in 2021 by QFs projected to come on line in 2020 is provided in Attachment 001-A, range T10:AE63. 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 017-A, range AI10:AT63.

d) The total nameplate capacity for QFs projected to come online in 2020 is provided in Attachment 001-A, cell R64. The total energy projected to be delivered by these QFs in 2021 is provided in cell AF64 with the total associated cost in cell BI64.

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

UE 377

Attachment 017-A

Provided in Electronic Format Only

Protected Information Subject to Protective Order 20-100

2020 QFs in the 2021 AUT

UE 377/PGE
OPUC Data Request 18

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 018
Dated May 15, 2020

Request:

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, and the percentage of actual to projected purchased power cost.

Response:

PGE objects to this request on the basis that it is vague. Without waiving and notwithstanding this objection PGE responds as follows:

PGE cannot provide actual total purchased power costs for new QFs expected to come online in 2020 and 2021 since we currently are in Q2 of 2020.

PGE has provided projected and actual costs of new QFs for the years 2016 to 2019 in our April 1 NVPC filing , Volume 9 - MFR documentation in support of the 83 percent derate applied to the forecast generation of QFs that have not achieved commercial operation.

UE 377/PGE
OPUC Data Request 20

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 020
Dated May 15, 2020

Request:

Please provide an excel file showing the original Pioneer solar QF hourly shaping and the updated hourly shaping.

Response:

PGE does not have an executed Schedule 201 or 202 QF agreement with Pioneer solar QF.

UE 377/PGE
OPUC Data Request 21

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 021
Dated May 15, 2020

Request:

Please provide each new QF project since 2019 included in the 2021 AUT.

Response:

Attachment 021-A provides QFs included in PGE's 2021 NVPC forecast that were not included in PGE's 2019 NVPC forecast.

UE 377/PGE
OPUC Data Request 92

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 092
Dated June 4, 2020

Request:

Please provide PGE's forecast for the years 2015 through 2019 as contained in each year's respective power cost filing of QF MWh and purchased power costs for each QF contract. The information should be provided in the same format as the company's response to Staff Data request 16, attachment A., and could be provided through inserting additional columns in that data respect response.

Response:

PGE objects to this request on the basis that it is vague and overly broad. Without waving and notwithstanding this objection, PGE responds as follows:

Attachment 093-A supplements PGE's response to OPUC Data Request 016, Attachment 016-A, to include 2015 through 2019 forecast generation and cost associated with QF projects currently online. Please see worksheet "Summary" within Attachment 092-A.

Additionally, as the above request refers to all QF agreements included in PGE's NVPC forecasts from 2015 through 2019, Attachment 092-A includes the final MONET energy and cost output worksheets for the respective years, containing all QF agreements effective in that year.

Attachment 092-A is protected information subject to Protective Order No. 20-100.

UE 377

Attachment 092-A

Provided in Electronic Format

Protected Information Subject to Protective Order 20-100

QF Actual and Forecast Energy and Costs
2015-2019

UE 377/PGE
OPUC Data Request 93

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 377
PGE Response to OPUC Data Request No. 093
Dated June 4, 2020

Request:

Please explain and describe how PGE forecasts for these contract, both the MWh and purchased power costs for the test period 2021.

Response:

PGE objects to this request on the basis that it is vague and overly broad. Without waiving and notwithstanding this objection, PGE responds as follows:

PGE assumes this data request refers to QF contracts modeled in PGE's 2021 NVPC forecast.

As provided in PGE's response to OPUC Data Request No. 023, PGE is forecasting the QF generation based on information provided in the executed Schedule 201 or 202 QF agreements. The QF agreements provide expected commercial operation dates and, in most cases, also provide information regarding the facility projected generation. If the agreement does not include projected generation PGE would use generation data from a proxy resource. Please see QF agreements in PGE's April 15 MFRs, Vol 5 – Contracts for additional information.

The forecast of the QF purchased power costs are, for most QFs, based on Schedule 201 avoided cost pricing schedules approved by the Commission. For some QFs, negotiated pricing information may be applicable and included separately in the power purchase agreement. The applicable Schedule 201 avoided cost prices are included in PGE's April 15 MFRs, Volume 5/Contracts, in folder "QF Prices – Sch 201". Schedule 202 QFs could have pricing information in the respective power purchase agreements.

CASE: UE 377
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

Non-Confidential
June 26, 2020

Staff Exhibit 403 is confidential

And filed in electronic format.

Subject to

Protective Order no: 20-100