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February 6, 2024

Via Electronic Filing

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

RE: Docket No. UE 427 In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Renewable Resource Automatic Adjustment Clause

Attached for Staff Opening Testimony filing are the following exhibits, certificate of service and service list:

PGE UE 427 Exh 100_102 RW
PGE UE 427 Exh 200_207 CD HI-CONF
PGE UE 427 Exh 207 HI-CONF Attach DR Response 15 (electronic)
PGE UE 427 Exh 207 HI-CONF Attach DR Response 1 (electronic)
PGE UE 427 Exh 300_302 HI-CONF AK

/s/ Kay Barnes
Oregon Public Utility Commission
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CASE: UE 427
WITNESS: RAWLEIGH WHITE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 100

Opening Testimony

February 6, 2024

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

A. My name is Rawleigh White. I am a Senior Financial Analyst employed in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program 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 qualifications statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overall summary of the Clearwater Wind Project (Clearwater), the revenue impact to customers, a summary of proposed stipulations or agreements, depreciation analysis, rate spread analysis and an introduction of additional Staff witnesses and short summary of their findings.

Q. Did you prepare any exhibits for this docket?

A. I prepared no exhibits other than my witness qualifications statement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. PROJECT SUMMARY AND REVENUE IMPACT

Q. What is the purpose of the UE 427 docket?

A. Portland General Electric Company (PGE) is requesting to amortize the revenue requirement impact for Clearwater through PGE's Schedule 122, Renewable Automatic Adjustment Clause (RAAC).[1] The RAAC allows new renewable resources to be added into rates as they are placed into service. PGE is requesting that the tariff effective date be June 1, 2024.[2]

Q. Please describe the Clearwater Wind Project.

A. Clearwater is a 776 MW wind generation project located approximately 30 miles North of Miles City, Montana in which PGE purchased 208 MW through a build-transfer-agreement (BTA) and acquired an additional 103 MW through a power purchase agreement from NextEra Energy Resources (NEER). The remaining MWs are neither owned nor operated by PGE.

Q. Will there be a deferral associated with Clearwater?

A. In docket UM 2306, PGE is requesting a deferral for costs associated with the testing and commissioning of Clearwater and net amounts incurred after the commercial operation date (COD) but prior to the tariff effective date of June 1, 2024. Staff is intending to take up the deferral request through the standard public meeting presentation. Also, see Dr. Dlouhy testimony at Staff/200 regarding additional details about the final COD.

Q. Was Clearwater part of a request for proposal (RFP) process?

[1] ORS 757.210 and 469A.120(3).
[2] PGE/100, Abel-Batzler/1-2.

A. Yes, the Clearwater project was evaluated under PGE's 2021 RFP. Dr. Dlouhy will provide additional information regarding the RFP process and the prudence of the Clearwater investment in his testimony, Staff/200.

Q. What is the revenue impact from the Clearwater project?

A. The revenue impact to customers is a decrease to PGE's revenue requirement of $28 million.[3]

Q. Please explain how a project acquisition results in a rate decrease for customers.

A. The 2024 net variable power costs (NVPC) forecasted and included in rates under Docket No. UE 416 did not include Clearwater. Including Clearwater in the 2024 forecasted NVPC model reduces the NVPC forecast cost by $92.6 million and when netted against Clearwater's operating cost, deprecation, taxes and return on rate base results in what is essentially a $28 million credit to customers.[4]

[3] UE 427 PGE Clearwater Renewable Resource Automatic Adjustment Clause – Net Variable Power Cost Update, December 8, 2023, Attachment 1.
[4] Id.

ISSUE 2. PROPOSED AND RECOMMENDED STIPULATIONS

Q. Is PGE proposing any adjustments or stipulations to the $28 million revenue requirement decrease?

A. The rate base in PGE's revenue requirement includes a deferred tax asset for production tax credits (PTCs) that PGE cannot currently utilize. Customers are receiving the full benefit of the PTCs in the forecast for NVPC. PGE is offering to remove the deferred tax asset for PTCs and attempt to sell them at a price that is no less than 90% of the current PTC value. This is the same term that is currently pending in PGE's Docket No. UE 416 general rate case.[5]

Q. Does Staff support PGEs recommended proposal to remove the PTCs from the rate base?

A. Staff supports PGE's proposal to remove the PTC from the rate base in determining the revenue requirement, which is what was done in Docket No. UE 416. Removing the PTCs from the rate base will reduce the Net Utility Plant from $435 million to $415 million.

Q. Is Staff proposing any rates or performance mechanisms for Docket No. UE 427?

A. Yes. Staff is proposing that a transmission related performance mechanism and a capacity factor mechanism be implemented as part of this docket. Dr. Dlouhy will provide additional information on Staff's performance mechanisms recommendation in his testimony, Staff/200. Anna Kim will provide additional

[5] UE 427 PGE/100, Abel – Batzler/36.

information on Staff's capacity factor mechanism recommendation in her testimony, Staff/300.

ISSUE 3. DEPRECIATION AND RATE SPREAD ANALYSIS

Q. Please describe how PGE estimated the 2024 Clearwater rate base of $432.6 million in its Opening Testimony.

A. PGE calculated the rate base for this filing similarly to how PGE typically treats new capital additions. This process involved the following steps:[6]

(1) PGE estimated the gross plant amount as of December 31, 2023, which was the expected commercial operation date (COD). This amount totaled roughly $432.7 million.

(2) PGE then applied a full-year estimate of accumulated depreciation. This amount totaled roughly ($16.8) million.

(3) PGE then applied a full-year estimate of deferred income taxes using a full-year of depreciation expense as the basis. This amount totaled roughly $19.3 million and was related to carrying forward unutilized Production Tax Credits (PTCs) generated by the project. This amount is to be removed as discussed in Issue 2 above.[7]

(4) Lastly PGE applied a full-year forecast of working capital using a full-year forecast of operating expenses and taxes.

Q. Does Staff have any concerns with PGE's rate base calculation?

A. Yes. As Staff has expressed in previous dockets, it would prefer that PGE used the average-of-monthly-averages (AMA) approach over the Test Year to

[6] See PGE Workpaper "Clearwater RevReq_GB_10.2.23_CONF".
[7] Staff/100, White/4.

calculate the rate base for purposes of establishing the return component of PGE's revenue requirement.[8]

Q. How would using the AMA methodology affect PGE's forecasted revenue requirement in this filing?

A**.** Minimally. In this case, PGE is applying a full year of accumulated depreciation to the December 31, 2023, gross plant value. This effectively is using the net plant value as of December 31, 2024, as the basis for establishing the return component of PGE's revenue requirement. Using Staff's preferred method, the AMA rate base value would be calculated beginning on the rate effective date of June 1, 2024, and ending on June 1, 2025. This would effectively value the plant at the mid-point of these dates - roughly December 2024.

Due to the COD and rate effective date in this case, Staff's and PGE's preferred methodologies arrive at roughly the same rate base valuation. As such, Staff is not suggesting an adjustment to the rate base value in this case but does reiterate that the AMA calculation is more accurate.

Q. Please describe how PGE is proposing to spread the revenue requirement in this filing.

A. PGE is proposing to spread the revenue requirement based on an equal percentage of generation revenue.

Q. Does Staff have any concerns with PGE's rate spread proposal?

A. No. Staff agrees that this rate spread methodology is reasonable.

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[8] See UE 416 for an in-depth discussion of this topic.

ISSUE 4. ADDITIONAL WITNESSES AND SUMMARY FINDINGS-

Q. Are there any additional witnesses for the UE 427 docket in this testimony?

A. Yes. Dr. Dlouhy will be providing testimony on the issues of investment prudence and related transmission for Clearwater in Staff/200. Dr. Dlouhy's testimony found Clearwater to be a prudent investment as the project was the lowest cost bid in a request for proposal process but there were questions regarding the transmission of the energy to PGE. As a result of the transmission concerns, Staff is proposing that certain transmission-related performance mechanisms be implemented.

Anna Kim, Energy Cost Section Manager, will provide testimony on the validity of PGE's inclusion and calculation of Clearwater in determining the adjustment for net variable power costs (NVPC) in the revenue requirement. Anna's testimony recommends a reduction in the NVPC used in this docket and two different adjustments for future power cost dockets. The first adjustment will fix the capacity factor in the AUT forecast for the first five years. The second adjustment applies a performance mechanism to the Power Cost Adjustment Mechanism. See Staff/300.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 427
WITNESS: RAWLEIGH WHITE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

February 6, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Rawleigh White, CPA, CFA

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst employed in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC)

ADDRESS: 201 High Street SE. Suite 100, Salem, OR 97301

EDUCATION: Eastern New Mexico University BBA, Finance and Accounting. Certified Public Accountant, Chartered Financial Analyst

EXPERIENCE: My current experience is focused on rates, purchase gas adjustments, renewable projects, affiliates, and results of operations. Following are a few of the dockets I have worked on and in certain instances orally presented in an OPUC public meeting: UI 490, UM 903, UE 416, UE 422, UG 468, UG 477, UG 478, UG 485, UM 2191, UM 2252, ADV 1568, UP 425, UG 461.

I have over 20 years of experience in the utility and power industry most recently as the Chief Financial Officer for Central Electric Cooperative (CEC). As the CFO of CEC, I was responsible for developing, presenting, and recommending retail and wheeling rates to the governing board of directors of the utility. For a portion of my tenure at CEC, I concurrently served as the General Manager of Quantum Communications, a regional telecommunications company.

Prior to CEC I was the CFO at the Confederated Tribes of Warm Springs (CTWS). My experience as the CFO at CTWS included the purchase and financing of the Pelton and Round Butte hydroelectric dams.

Prior to my CTWS experience, I was the Director of Corporate and International Accounting for Pioneer Natural Resources, a publicly traded oil and gas company. I was involved in accounting matters domestically as well as in Argentina, Gabon, and South Africa.

At the beginning of my career, I worked as an auditor for KMPG and Arthur Andersen.

CASE: UE 427
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

February 6, 2024

Q. Please state your names, occupations, and business address.

A. My name is Curtis Dlouhy. I am an economist employed in the Strategy and Integration 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 backgrounds and expertise.

A. My witness qualifications statement can be found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the prudence of the Company's acquisition of Clearwater.

Q. Did you prepare any exhibits for this testimony?

A. Yes. I prepared seven exhibits:

- Exhibit Staff/201 – Witness Qualification
- Exhibit Staff/202 – Non-Confidential Responses to Data Requests
- Exhibit Staff/203 – Minimum Bidding Requirements for PGE's 2021 RFP
- Exhibit Staff/204 – 2021 RFP Scoring Methodology
- Exhibit Staff/205 – Interim Transmission Solution
- Exhibit Staff/206 – UM 2166 September 1, 2023, Memo from IE to Staff
- Exhibit Staff/207 – Highly Confidential Responses to Data Requests

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. UM 2166 AND CLEARWATER SELECTION

Q. What is the purpose of this section of testimony?

A. The purpose of this section of testimony is to provide a brief overview of the Request For Proposals (RFP) docket that ultimately led to the acquisition of the Clearwater Wind Project (Clearwater), UM 2166.

Q. What portions of the UM 2166 do you believe are relevant to determining whether Clearwater was a prudent investment?

A. There are many items that are relevant to determining whether Clearwater was a prudent investment, many of which the Company also highlighted in its UE 427 testimony. Among them:

- The requirements of the RFP and whether Clearwater met these requirements;
- Cost characteristics of Clearwater's bid and Clearwater's overall bid score;
- Cost characteristics of other bids in UM 2166 and their overall bid scores; and,
- Fairness in the execution of the RFP.

Q. What was PGE seeking to acquire in with its RFP?

A. PGE sought proposals for renewable and dispatchable resources. Any renewable resources were required to pass a cost containment screen, qualify for federal investment tax credits (ITCs) or production tax credits (PTCs), and have energy production below 150 MWa.[1]

Q. What projects were selected as a result of this RFP?

A. Ultimately, PGE opted to build four projects following the RFP, all of which were benchmark bids. Three of these projects are dispatchable energy resources that are standalone batteries, the 200 MW Troutdale Battery Energy Storge (BESS) facility, the 200 MW Seaside BESS facility, and the 75 MW Evergreen BESS facility.[2] The fourth facility is the subject of this docket, the 300 MW Clearwater wind facility.

Q. What were the minimum requirements to bid into PGE's 2021 RFP

A. The full minimum bidding requirements are included in Exhibit 203, which contains an excerpt of PGE's All-Source RFP Final Draft submitted in UM 2166 on October 15, 2021.[3] Of particular note to this docket, PGE requested that resource bids have a commercial online date of December 2024, renewable bids have an achievable plan for long-term transmission service for 80 percent of the interconnection limit of the facility, power purchase agreements have term lengths between 15 and 30 years, and wind resources have a nameplate capacity of at least 10 MW. PGE also requested that renewable resource bids target a size of 150 MWa.

Q. How were bids scored in the RFP?

[1] See page 1 of PGE's April 28, 2021, filing in UM 2166, here.
[2] See the Independent Evaluators Final Report filed on June 30, 2023 in UM 2166, here.
[3] Staff/203, Dlouhy/4

A. The full scoring methodology are included in Staff Exhibit 204,[4] which contains Appendix N to PGE's All-Source RFP Final Draft submitted in UM 2166 on October 15, 2021. At a high level, each bid could earn up to 1000 points where higher scores are considered stronger bids. Of those 1000 points, 700 are awarded based on a project's cost to benefit ratio while the remaining 300 are awarded based on non-price components of the bid. The non-price scoring criteria varied between dispatchable and renewable bids, but the renewable resource scoring is the only criteria relevant to this docket. Components of the non-price score for renewable bids include 212 possible points based on the project's commercial performance risk, 29 possible points for the transmission plan attributes, and 59 possible points based on the resource's ratio of capacity contribution to energy production.[5]

Q. What elements of PGE's RFP process did Staff analyze when determining the prudency of Clearwater?

A. Staff analyzed the following factors from UM 2166 when determining the prudency of Clearwater:

- Clearwater's construction milestones and whether they were achieved in a timely manner;
- The cost and plant parameters submitted as part of the Clearwater bid and whether these parameters align with information submitted about the Clearwater facility in UE 427;

[4] Staff/204, Dlouhy/1.
[5] Staff/204, Dlouhy/20.

- Other concerns from UM 2166 that may have led to a less than competitive outcome.

Q. When considering these factors, do you believe that the Clearwater facility is a prudent investment?

A. Staff believes that Clearwater could be considered a prudent investment if a transmission-access performance-based cost recovery mechanism is included and the way that the 2021 RFP was conducted were fair. The Clearwater facility appears to have been the winner from a cost perspective. Further, the facility seems to have met all internal production deadlines and almost reached its target commercial online date target of December 2023. The gross plant cost and capacity factor submitted as part of the Clearwater bid are also generally in line with the costs and capacity factor submitted in UE 427.

However, Staff has concerns about how the RFP was conducted and believes that these concerns may have led to a less than competitive outcome, possibly to the expense of retail customers. In particular, Staff notes that in 2021 RFP, the Clearwater bid was given different treatment regarding its transmission access issues than other similarly situated bids. The transmission access requirement in the RFP and PGE's different treatment of the requirement towards Clearwater when compared to other similarly situated bids appears to have led to some bids withdrawing from the process. Staff worries that the perception that a benchmark bid would receive preferential treatment may have led to some bidders choosing not to bid at all. Having bidders withdraw from the procurement needlessly only harms retail customers in that fewer alternative resource project proposals end up being considered. Some of these alternatives could have been lower cost to retail customers.

To balance these concerns, Staff recommends that the Commission determine that Clearwater was a prudent investment given that certain transmission-related performance mechanisms are also implemented.

Q. Are there any other prudent related comments you wish to offer?

A. Yes. Prudence determinations are based on what the utility knew or should have known at the time it is making its decisions. Given that the results of the RFP and the time PGE needed to commit to beginning its resource acquisitions, it is appropriate to analyze prudence based on the results of the RFP.

ISSUE 2. CLEARWATER BID AND MILESTONES

Q. What is the purpose of this section of testimony?

A. This section of testimony provides an overview of the information submitted as part of Clearwater's bid in response to the RFP, an overview of the project's timelines and milestones, and a discussion about how well the Company met the milestones and project parameters as submitted in the RFP.

Q. Please provide an overview of the Clearwater bid in UM 2166.

A. The Clearwater bid was submitted as a benchmark bid by PGE and NextEra.[6] The bid itself was for a total of 311 MW and consists of two parts:

- 208 MW of the Clearwater East facility that was built by NextEra then transferred to PGE via a build-transfer agreement (BTA); and
- 103 MW of Clearwater II that will be sold to PGE under a power purchase agreement (PPA).

Although the project consists of 311 MW of generation, the bid was limited to 300 MW of total output at the point of interconnection, which is the Colstrip substation.[7]

Q. What project parameters and milestones did Staff analyze as part of the prudence review?

A. Staff analyzed the following items:

- The target commercial online date as well as other project milestones;
- The project costs submitted as part of the bid; and

[6] PGE/100, Abel – Batzler/16.
[7] PGE/100, Abel – Batzler/18, Footnote 29.

- The projected capacity factor as reported in UM 2166 and the actual capacity factor used for rate setting.

In general, Staff found that the Company's information submitted as part of its benchmark bid in UM 2166 adequately aligns with the information submitted in this docket.

Q. What was the target commercial online date for the Clearwater facility?

A. In its opening testimony, PGE states that it targeted commercial operation by December 2023 for both Clearwater East and Clearwater II.[8] PGE filed its opening testimony on October 30, 2023, which was before the scheduled commercial operation date. Staff issued a data request in December asking whether PGE was able to meet this target as well as other milestones listed in its opening testimony.

Q. Was PGE able to meet the commercial online date for each facility?

A. The Company confirmed that Clearwater II began operating commercially by December 11, 2023.[9] However, as of the Company's response to Staff DR 18 on December 26, 2023, the Company had not finished the Final Wind Farm Commissioning or achieved commercial operation for Clearwater East. On January 12, 2024, Staff issued a data request to confirm whether the commercial online date had been achieved for Clearwater East. The Company responded that Clearwater East finished its Final Wind Farm Commissioning

[8] PGE/100, Abel – Batzler/37.
[9] Staff/202, Dlouhy/3-4.

on December 30, 2023, and achieved commercial operation on January 5, 2024.[10]

Q. Does Staff believe that this delay impacts the prudence of PGE's selection?

A. No. Staff notes that the delay only led to Clearwater East missing its commercial online date by five days. While it would have been ideal for Clearwater East to be completed on time, Staff finds a delay of a few days over a multi-year construction process for an asset with a 30-year economic life to be trivial. Given that the rate effective date of this docket is June 1, 2024, Staff sees no reason that this delay should impact the forecasted costs used to set the rates in Schedule 122.

Q. What was the expected cost of the Clearwater facility when the bid was submitted?

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

Q. How did these costs align with the amounts used to calculate the revenue requirement in this docket?

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[10] Staff/202, Dlouhy/7.

A. **[BEGIN HIGHLY CONFIDENTIAL** [redacted] **[END HIGHLY CONFIDENTIAL]** PGE's filed workpapers contain the gross plant used to calculate revenue requirement for Clearwater East in Exhibit 101 and in their revenue requirement update filed on December 8, 2023.[11,12] In both documents, the gross plant is listed as $432 million. **[BEGIN HIGHLY CONFIDENTIAL** [redacted] **[END HIGHLY CONFIDENTIAL]** Staff finds no reason to deem Clearwater East imprudent based on the actual gross plant value.

Q. What capacity factor was used in the Clearwater bid in UM 2166?

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

Q. How does this align with the capacity factor that PGE uses to calculate the power cost benefits of Clearwater East?

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END**

[11] PGE/101.
[12] See PGE's UE 427 filing on December 8, 2023, here.

HIGHLY CONFIDENTIAL] Staff was initially concerned that the Clearwater bid may have been providing an overly optimistic outlook on its generation and investigated the difference between the capacity factor in UM 2166 and used when calculating power costs.

To do this, Staff analyzed the workpapers submitted by PGE to calculate short- and long-term transmission availability for Clearwater. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Staff will explain later our concerns about Clearwater's transmission procurement. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Staff is satisfied that the capacity factor used in power cost modeling is reflective of the capacity factor used in the Clearwater bid.

Q. Based on your analysis of the information submitted into UM 2166 and what is being placed into rates, do you find any reason to deem Clearwater imprudent so far?

A. While Staff has other reasons to question the prudency of Clearwater, Staff finds that the information provided when bids were being scored is adequately in line with the information that PGE is providing in this filing and provides no reason to deem Clearwater imprudent.

ISSUE 3. UM 2166 TRANSMISSION ISSUES

Q. What is the purpose of this section of testimony?

A. The purpose of this section is to outline transmission issues and unequal treatment that occurred during the course of PGE's 2021 RFP, which were identified in UM 2166.

Q. Why does Staff feel that this is important to call out in the prudence review for the Clearwater facility?

A. Staff notes that Clearwater has only secured 230 MW of long-term firm transmission from the Clearwater facility to PGE's load. In effect, this is only 77 percent of the project's 300 MW nameplate capacity and below the 80 percent long-term firm transmission minimum requirement in PGE's RFP.[13]

While the IE deemed this "acceptable" given PGE's needs,[14] Staff is concerned that this may diminish the value of Clearwater to PGE's retail customers. Further, Staff notes that some similarly situated bids may have been dissuaded from bidding into the RFP and some similarly situated bids in the RFP were given different treatment than Clearwater.

Q. What is the significance of the 80 percent long-term firm transmission threshold that was used as a minimum bidding requirement?

A. The 80 percent of nameplate capacity was established as part of the Interim Transmission Solution, which is contained in Staff Exhibit 205. Prior to presenting the Interim Transmission Solution in PGE's 2019 IRP, renewable

[13] PGE/100, Abel – Batzler/19.
[14] Id.

projects that bid into a PGE RFP were required to demonstrate long-term firm transmission service for 100 percent of the project's nameplate capacity by the project's commercial operation date. Following a stakeholder process, PGE proposed that renewable projects be required to demonstrate only 80 percent of the project's nameplate capacity be covered by long-term firm or conditional firm transmissions service as a way to balance deliverability risk with renewable bid feasibility. PGE explains in the Interim Transmission Solution that the solution was meant to:

- Enable a fair, transparent, and competitive renewable resource procurement process;
- Provide reasonable assurances of delivery, project success, and value to customers;
- Adequately identify and mitigate potential cost shifts to customers and PGE;
- Adequately identify and mitigate potential risk shifts to customers and PGE; and,
- Appreciate differences between dispatchable and variable resources as appropriate[15]

Q. How does Staff believe that the Interim Transmission Solution should be viewed in the context of the prudency of Clearwater?

[15] Staff/205, Dlouhy/6.

A. The Interim Transmission Solution aims to balance the feasibility of renewable resource requirements while still ensuring that costs and risks aren't unduly shifted onto the Company's customers. The Interim Transmission Solution inherently recognizes that there is added cost and risk by only requiring a renewable project to have 80 percent of its nameplate capacity covered by long-term firm or conditional firm transmission rights. Staff is concerned that a failure to meet even this more flexible requirement could unfairly burden the Company and its customers.

Q. Are there other reasons that Staff believes that insufficient long-term firm transmission may diminish the value of Clearwater to customers?

A. The West is in a period of significant transmission tightness caused by increasing loads, a heavier reliance on renewable generation, and increasingly common extreme weather events driven by climate change. This has manifested in many instances where renewable load may need to be curtailed due to insufficient transmission, particularly in extreme weather events and other times of transmission scarcity during high demand.

To analyze the extent of this concern, Staff issued a Data Request asking PGE to compile a list of instances where it had to curtail generation due to insufficient transmission. While PGE was unwilling to complete its response to Staff's request in a timely matter and did not answer the specific request, PGE noted that PGE is subject to transmission Remedial Action Schemes (RAS) from Bonneville Power Administration (BPA), which has led to curtailment on occasion.[16] PGE also notes in its response that curtailment can happen through the Western Energy Imbalance Market (EIM) as well.

Q. Why was the Clearwater bid allowed to continue in the RFP despite having insufficient transmission?

A. According to the September 1, 2023, memo from the IE to Staff regarding the 2021 RFP in Staff Exhibit 206, the IE noted that non-conforming bids were often instructed to resize their bids in order to conform to the minimum transmission requirement and does not know why this same treatment was not applied to Clearwater.[17] This was different than the treatment of bids from **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**.[18]

Q. How far from meeting this transmission requirement was Clearwater and what was the alternative transmission plan for Clearwater?

A. Clearwater secured only 180 MW of approved capacity to deliver energy from BPA to PGE, which was only 60 percent of their approved capacity. To make up for its shortfall, PGE suggested that it use 50 MW of transmission from Snohomish PUD and make up for the remainder of the shortfall using existing Mid-C transmission rights. This is, however, only a short-term solution that expires in December 31, 2025. The IE noted that neither of these transmission rights were made available to other bidders. However, the IE ultimately found

[16] Staff/202, Dlouhy/5-6.
[17] Staff/206, Dlouhy/8.
[18] Staff/206, Dlouhy/4-5.

that this alternative plan was acceptable enough to let the project continue in the RFP.[19] Staff notes that the alternative plan intends to use the PGE's transmission rights associated with Colstrip.[20] These were assumed to be not available on a firm basis until after the closure of Colstrip. The Colstrip Transmission System (CTS) rights were not provided as an option in this RFP **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**.[21]

Q. Were other projects in the RFP given the same treatment?

A. No. The September 30 memo from the IE to Staff highlights that other bids with insufficient transmission were given different directions about how to continue being considered in the RFP. The IE highlights **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** in particular. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**[22] At the initial screening stage, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** was informed that it should downsize its bid **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** as a way to bring its transmission in line with the

[19] Staff/206, Dlouhy/2-3
[20] Id.
[21] Staff/206, Dlouhy/5.
[22] Staff/206, Dlouhy/6.

minimum requirements. This ultimately led to the bid being withdrawn. Although the IE felt that PGE evaluators intended on making the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** bid as competitive as possible, the IE noted that they should have pushed harder for its inclusion to give it the same treatment as Clearwater.[23]

Q. Were bid scorers at PGE concerned about Clearwater not meeting the 80 percent minimum transmission requirement?

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

Staff notes that PGE's plan to deliver power from Clearwater presented in this docket does not rely on Colstrip's transmission rights.[25]

Q. How did the cost of Clearwater compare to [BEGIN HIGHLY CONFIDENTIAL] [redacted] [END HIGHLY CONFIDENTIAL]?

[23] Staff/206, Dlouhy/10.
[24] Staff/207. Filed electronically.
[25] PGE/100, Abel – Batzler/18.

A. The IE noted that **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **END HIGHLY CONFIDENTIAL]** was not competitive to PGE as it was proposed.[26] Therefore, it was unlikely to having a winning bid in the RFP. However, Staff believes that the impression of an unfair RFP process or a selectively enforced transmission minimum requirement may have led to bidders choosing to not bid into the RFP, thus leading to a less competitive RFP to the detriment of customers.

Q. Even with structural aspects of the RFP possibly aiding a benchmark bid, was Clearwater able to meet the minimum transmission requirement?

A. No. As PGE points out in its opening testimony, Clearwater only has 77 percent of its nameplate capacity covered by long-term firm transmission. Staff inquired as to whether there were other options available to meet the 80 percent requirement. The Company states that even with the 50 MW from Snohomish County PUD, PGE was unable to meet this.[27] **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[26] Staff/206, Dlouhy/10.
[27] Staff/202, Dlouhy/2.

[redacted]

[END CONFIDENTIAL]

Level 3 - Restricted

ISSUE 4. PRUDENCY OF CLEARWATER

Q. Given the findings about Clearwater's execution and concerns about transmission and the RFP process, does Staff believe that PGE's acquisition of Clearwater was done prudently?

A. Staff believes the acquisition of Clearwater was prudent but does not support recovery of all costs in light of PGE's decisions related to the Transmission requirements for Clearwater. If Clearwater experiences significant transmission shortfalls in the future or experiences significant added costs of acquiring transmission, Staff does not believe the costs associated with these shortfalls should be borne by customers. Staff makes this determination after seeing that Clearwater did not meet the minimum transmission requirements for its own RFP in an era of increased transmission tightness, other similarly situated bids dropped out after being given different directions about how to remedy transmission shortfalls, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** However, the Clearwater bid passed the cost screen and appears to have been the lowest-cost BTA option in the RFP in the way the bid was evaluated.

Q. What does Staff recommend to address costs that stem from PGE's assumptions regarding available Transmission for Clearwater?

A. Staff recommends that cost recovery for Clearwater should be subject to two conditions.

1. The net variable power cost (NVPC) forecast used to determine Clearwater's revenue requirement should be recalculated assuming that Clearwater has long-term firm transmission rights equal to 80 percent of its nameplate capacity.
2. A performance-based mechanism should be attached to the recovery of power costs associated with Clearwater.

Q. What is the effect on overall revenue requirement of assuming that Clearwater has 80 percent of its nameplate capacity covered by long-term firm transmission rights?

A. Staff calculates the new overall revenue requirement by recalculating the NVPC assuming that Clearwater has 80 percent long-term firm transmission. This results in a decrease in overall NVPC by $1.338 million. Staff Witness Anna Kim outlines Staff's methodology to calculate this adjustment in Staff Exhibit 300.

Q. Please explain the performance mechanism that Staff recommends be attached to Clearwater.

A. Staff recommends that the performance mechanism contain two pieces. First, Staff recommends that the cost of the first 10 MW of short-term transmission rights used to deliver power from Clearwater to PGE's load at any given time be held out of the PCAM or any other cost recovery docket. In effect, this holds ratepayers harmless from PGE acquiring transmission rights to deliver 80 percent of Clearwater's nameplate capacity, which was the minimum RFP requirement.

Second, Staff recommends that whenever Clearwater is unable to deliver generated power to PGE's load due to lack of available transmission, any marginal power costs incurred to cover this shortfall be excluded from the results of the Power Cost Adjustment Mechanism (PCAM). Staff makes this recommendation with the understanding that Clearwater is able to sell power to other balancing authorities. When calculating amount of marginal power cost to be removed from the PCAM, Staff recommends that the marginal power cost incurred to make up for Clearwater non-deliverability include any curtailment fees that PGE is responsible for and be netted against any revenues that PGE earns from selling power from Clearwater to another balancing authority. This amount could be estimated by calculating the highest marginal cost resource or market purchase and transmission costs in the hours where Clearwater output is curtailed to the counterfactual energy and transmission costs if Clearwater had sufficient transmission at the market rate at the time of the curtailment.

Q. Why do you believe that this is a fair treatment for Clearwater?

A. The selection of Clearwater came during an RFP where Staff had significant concerns about the fairness of the RFP process. In effect, Staff worries that more cost-effective projects may have been available. Staff also has concerns about Clearwater's ability to deliver power during hours of transmission tightness due to it failing to meet the minimum transmission requirements of the RPF. With all this in mind, Staff struggled to recommend that the Commission determine that Clearwater was a prudent investment.

Conversely, Staff notes that Clearwater submitted an ultimately winning bid in an RFP that was approved by an IE and was found to be beneficial to PGE's system through the cost test. Further, the actual costs, plant attributes, and online date appear to be suitably in line with what was promised during the RFP. Therefore, Staff believes that had Clearwater accounted for costs to acquire the required transmission, it may still have been selected as a winning bid. However, this is still hard to determine if one believes that other bidders were discouraged from even submitting a bid into the RFP due to a perception that the administration of the RFP was unfair.

To balance these concerns, Staff finds it reasonable to find Clearwater prudent and allow cost recovery subject to Staff's conditions. If the transmission shortfall rarely or never manifests, then in effect PGE would recover all or nearly all the costs associated with Clearwater. However, if Clearwater fails to deliver on a more consistent basis, then customers are protected in part from deleterious effects arising from its imprudence.

Q. Suppose that there is a transmission shortfall event, PGE chooses to export Clearwater's power to a neighboring BAA, and the net financial effect of this is positive, including the cost of purchasing an equivalent amount of power and have it delivered to PGE's system. Should PGE's financial windfall also be kept out of the PCAM?

A. No. In this case, PGE's choice to export power to another BAA would be considered prudent even under normal conditions and thus should be included in the PCAM. The impact of this alternative is captured by the reduced PGE load scenario discussed just prior in my testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 427
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

February 6, 2024

WITNESS QUALIFICATION STATEMENT

NAME:	Curtis Dlouhy
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Economist, Strategy and Integration Division
ADDRESS:	201 High St. SE, Ste. 100 Salem, OR 97301-3612
EDUCATION:	PhD, Economics University of Oregon, Eugene, OR Master of Science, Economics University of Oregon, Eugene, OR Bachelor of Arts, Economics & Math Nebraska Wesleyan University, Lincoln, NE
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) in the Strategy and Integration Division since April 2022 and had previously worked in the Rates, Finance, and Audit Division since June 2020. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have provided analysis and expert testimony in various contested cases including UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394, UG 433, UG 435, UE 399, UE 400, UE 402, UE 416, UE 420, and UE 427 (ongoing). Prior to working for the Commission, I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization, and Antitrust Economics. My PhD dissertation won an award from the Transportation and Public Utility Working Group and covered topics in fossil fuel markets ranging from coal mine closure, dispatchable electricity choices under carbon taxes, and coal transport via railroad. While completing my PhD, I provided economic analysis for the Graduate Teaching Fellows Federation as a member of its contract bargaining team.

CASE: UE 427
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Non-Confidential Responses to Data Requests

February 6, 2024

January 04, 2024

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 427
PGE's *First Revised* Response to OPUC Data Request 016
Dated December 11, 2023

Request:

Please provide the expected capacity factor, initial expected project cost, updated expected project cost, and expected Effective Load Carrying Capability of the Clearwater bid.

Original Response (dated December 26, 2023):

Expected Net Capacity Factor	32.9%
Initial Expected Project Cost – Real Levelized - $/MWh	$51.91
Updated Expected Project Cost – Real Levelized - $/MWh	$51.28
ELCC	109 MW

Revised Response (dated January 04, 2024):

PGE inadvertently provided an incorrect figure for Expected Net Capacity Factor within the above originally provided table. The following table provides the correct Expected Net Capacity Factor as included within PGE's price score modeling for UM 2166:

Expected Net Capacity Factor	43.4%
Initial Expected Project Cost – Real Levelized - $/MWh	$51.91
Updated Expected Project Cost – Real Levelized - $/MWh	$51.28
ELCC	109 MW

December 26, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 427
PGE Response to OPUC Data Request 017
Dated December 11, 2023

Request:

Refer to PGE/100, Abel – Batzler/19. Please discuss whether there are any other sources of long-term firm transmission that PGE could have used to cover the 80 percent long-term firm transmission requirement. If another transmission source existed at the time of the UM 2166 acknowledgement decision, please provide an estimate of the additional cost to procure enough transmission to meet the 80 percent threshold.

Response:

PGE explored options to meet the 80 percent long-term firm transmission requirement and acted upon the available 50 MW of long-term transmission service by Snohomish County PUD. The additional transmission options were discussed in PGE/100, Abel – Batzler/20. There were no other available options for the Clearwater project.

December 26, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 427
PGE Response to OPUC Data Request 018
Dated December 11, 2023

Request:

Refer to Table 3 and Table 4 on PGE/100, Abel – Batzler/37. Please discuss whether each of the scheduled milestones were completed by the target date. For each milestone that was not completed by the target date, please provide a narrative description of why the milestone was not completed on time, the date the milestone was completed, and any added costs that were incurred associated with the delay.

Response:

In Table 3, Start of Construction, Test Energy, and Wind Turbine Mechanical Completion were all completed by the target date. Final Wind Farm Commissioning and Commercial Operation are in progress.

Table 3
Clearwater East Milestones

Milestone	**Scheduled/Actual Completion**
Start of Construction	May 2023 (Achieved)
Test Energy	November 2023
Wind Turbine Mechanical Completion	November 2023
Final Wind Farm Commissioning	December 2023
Commercial Operation	December 2023

In Table 4, Effective Date, Seller Approval Date, Test Energy and Commercial Operation were all completed by the target date.

Table 4
Clearwater II Milestones

Milestone	Scheduled/Actual Completion
Effective Date	October 2022
Seller Approval Date	December 2022
Test Energy	November 2023
Commercial Operation	December 11, 2023

January 05, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 427
PGE Response to OPUC Data Request 019
Dated December 11, 2023

Request:

Please provide a list of each instance since 2015 when the Company had to curtail generation at one of its generating facilities or otherwise was unable to deliver generation to meet its load due to insufficient transmission. When responding to this, please list the date, the cause, the size of the curtailment, and the facilities that were curtailed for each instance.

Response:

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

While PGE has limited generation due to transmission constraints, PGE does not have a system in place that can accurately compile every event occurrence. Curtailment due to transmission constraints can occur for many different reasons. Historically, PGE hasn't had a business need for specifically tracking these types of events and hence, a summary of instances when generation had to be curtailed due to transmission limitations is unavailable.

For context:

1. PGE is subject to System Operating Limits (SOL) from the Transmission Operator (TOP), Bonneville Power Administration (BPA) and changes can be implemented for a variety of reasons: transmission components failing, components taken out of service for maintenance or other reasons, system issues (including fires near transmission lines and fire risk mitigation), and at operator discretion.

2. PGE is also subject to transmission Remedial Action Schemes (RAS), which are in place to protect the transmission system. The wind farms are included as part of a RAS that is controlled by BPA and have been activated (tripped offline) in the past on rare occasions.

3. BPA also imposes Rate of Change Constraints, including one that impacts PGE's wind farms. CAISO's EIM system calculates the Rate of Change of PGE's wind farms based on information contained in their Business Practice Manual (BPM), and CAISO's system will issue a curtailment on the wind farm(s) to prevent exceeding the Rate of Change Constraint. These rate of change curtailments show up in our system the same as all market

curtailments, such as low pricing. Therefore, PGE does not have specific details for all Rate of Change Constraint events where CAISO identified and reduced PGE's wind generation.

It should also be noted that due to provisions included in the Clearwater power purchase agreement (PPA), PGE is required to track curtailments for Clearwater II. Additionally, because Clearwater does not have rights to 100% firm transmission for delivery due to BPA transmission capacity limitations adjacent to the Montana transmission system where Clearwater physically resides and because PGE has a contractual obligation to pay a compensable curtailment charge to NEER for its PPA portion, PGE includes modeling for both projected curtailment and short-term transmission purchase.

January 25, 2024

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 427
PGE Response to OPUC Data Request 036
Dated January 12, 2024

Request:

Refer to the Company's response to Staff DR 18. Please confirm whether the Final Wind Farm Commissioning and Commercial Operation are still in progress for Clearwater East. If they are completed, please provide the date by which they were completed. If they have not been completed yet, please provide a narrative description discussing what is causing the delay.

Response:

Final Wind Farm Commissioning was completed on December 30, 2023 and Commercial Operation was achieved on January 5, 2024.

February 2, 2024

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 427
PGE *First Supplemental* Response to OPUC Data Request 031
Dated January 2, 2024

Request:

Please provide the unredacted version of Staff's memo filed in UM 2166 on October 30, 2023, or provide permission for Staff to use the Highly Confidential information in this report in Docket No. UE 427.

Original Response (dated January 16, 2024):

PGE objects to this request on the basis that the information requested is not relevant nor reasonably likely to lead to the discovery of relevant evidence in the current proceeding.

Without waiving this objection, PGE responds as follows:

PGE has discussed with OPUC Staff its concerns about the accuracy of some of the statements included within the memo Staff filed in UM 2166 on October 30, 2023, and it is PGE's understanding that the Staff person who is currently working to revise that memo has been delayed due to other Staff business. PGE will update its response to this request once the referenced Staff memo has been revised.

Supplemental Response (dated February 2, 2024):

PGE continues to object to this request on the basis that the information requested is not relevant nor reasonably likely to lead to the discovery of relevant evidence in the current proceeding.

Without waiving this objection, PGE responds as follows:

It is still PGE's understanding that the above-referenced Staff memo will be revised. Without waiving PGE's objection to providing the October 30, 2023 Staff memo and without granting permission for Staff to use the Highly Confidential information within that Staff memo, PGE is supplementing its response to this data request. Following conversations with legal counsel for Staff, PGE is providing as Highly Confidential Attachment 031-A, the September 1, 2023 memo from Bates White, LLC to Staff, with the subject line: Answers to Staff Questions.

UE 427
PGE's *First Supplemental* Response to OPUC DR 031
February 2, 2024
Page 2

Attachment 031-A contains protected information and is subject to Modified Protective Order No. 23-431.

CASE: UE 427
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Minimum Bidding Requirements for PGE's 2021 RFP

February 6, 2024

Minimum Requirements

As part of the RFP PGE has the following requirements for participating resources. For additional discussion of these requirements please see Appendix N, PGE's approved scoring and modeling methodology.

Entity

As applicable, entities must be authorized under the law to sell power, and able to schedule power and operate under industry standards established by the Federal Energy Regulatory Commission (FERC), Western Electricity Coordinating Council (WECC), and the North American Energy Reliability Council (NERC), or other applicable regulatory body or government agency.

Financing

As applicable, Bidders must provide a reasonable plan to obtain project financing. Those Bidders who are unable to internally or balance sheet finance the proposed project (supported by appropriate financial statements) must provide evidence of a good faith commitment from a financial institution or lender prior to placement on PGE's final short list.

Technology

PGE will accept bids for resource core technologies that are commercially proven and deployed at large scales within the North American utility industry. Renewable resources bid into the solicitation must be RPS eligible. Dispatchable resources must be non-emitting technologies that can dispatch when called upon.

Bidders are responsible for ensuring and demonstrating that solar panels associated with any bid are not sourced from listed entities on the Department of Commerce - Bureau of Industry and Security's Entity List to ensure that projects do not include polysilicon produced with forced labor.

For energy storage facilities, Bidders must provide a list of major US installations of this storage technology. Storage medium, chemistry and power conversion systems of these installations must be of like kind to what is being proposed. Such installations must be in proved commercial operation beyond R&D demonstrations.

Online Date

All components of resources must be online no later than the end of 2024. For example, in the instance of a solar & storage resource, both the solar and storage components need to be online by 12/31/2024. PGE has made an exception for pumped hydro resources that have long lead times due to the unique value that they offer.[6] PGE is prepared to accept bids for those resources participating as long as all components of those resources come online by the end of 2027.

Qualifying Product

PGE shall be the sole offtake for all output from the facility or portion of the facility bid into this RFP. Projects must include all power attributes including associated renewable energy credits, environmental attributes, energy benefits, and capacity benefits.

Bidders with renewable resource bids will be responsible for ensuring RECs from renewable resources are bundled as defined in ORS 469A.005, and that they are established through Western Renewable Energy Generation Information System consistent with OAR 330-160-0020.

Nameplate Size

Resources that are bid into this RFP must be large enough to qualify for contracting under PGE's Schedule 202 for qualifying facilities.[7] Solar resources must be larger than 3 MW and all other facilities must be larger than 10 MW. If a Bidder has an existing Schedule 202 contract with PGE, PGE does not make any commitments to allow the Bidder to exit the existing agreement.

Term Length

For bids that include a power purchase agreement structure, PGE requests that bids have term lengths that are no shorter than 15 years and no longer than 30 years.

Tax Credits

Renewable resources must be eligible for the federal PTC or ITC and all renewable resource bids must demonstrate achievable qualification qualities and plan to establish how the project will obtain the tax credits.

Credit

Bidders must meet PGE's credit eligibility thresholds. For investment grade Bidders, their long-term, senior unsecured debt must be rated BBB- or higher by Standard & Poor's and Fitch, BBB (low) or higher by DBRS, or Baa3 or higher by Moody's Investor Services, Inc. For non-investment grade Bidders, they must demonstrate, prior to final short list, that a qualified institution will secure the Bidder's performance obligations through a letter of credit and guaranty, in a form acceptable to PGE.

Additional detail on PGE's credit requirements is included in Appendix K.

[6] PGE will also consider other long-lead time technologies that satisfy the remainder of PGE's eligibility requirements, have been commercially proven, and can be shown to require additional construction time beyond what is possible by 2024.

[7] This requirement is consistent with OAR 860-089-0250(4).

Site Control

Bidders must support the bid by demonstrating dependable site control, for both the location of the resource and any gen-tie path that is required. At the time of bid submission, Bidders must possess at least one of the following:

- title to the site
- an executed lease agreement
- an executed easement
- an executed option agreement applicable to a minimum of 80% of the project site

The site control documents should reflect the resource type bid into this RFP.

Prior to placement on PGE's final short list, bidders will be required to demonstrate site control for 100% of the project site.

Permitting

Please see Exhibit A in the Scoring and Modeling Methodology document included as Appendix N to this larger RFP document. The chart in Appendix N lists environmental permits and surveys commonly required for construction and operation of an energy project. For each permit and survey, the chart illustrates when the permit must be obtained, or survey must be completed – by bid, final shortlist, or construction – for different technologies. "By bid" requirements necessitate that the project receives the permit from the authorizing agency or the survey has been completed by the time of bid submission. "By final shortlist" requirements necessitate that the project receives the permit from the authorizing agency by the time PGE announces the final shortlist. "By construction" requirements necessitate that the project receives the permit from the authorizing agency before construction begins.

In the event a specific permit is not required at all or during the RFP process for the resources that are bid into this RFP, the Bidder may provide a narrative explanation on the bid form regarding why it is not applicable.

Delivery points

PGE will accept delivery within PGE's balancing authority area and at BPAT.PGE. PGE will not accept delivery at Pelton Round Butte or at PacifiCorp West.

The BPAT.PGE Point of Delivery (POD) is associated with the following substations or "sinks":

- PGE Contiguous
- Pearl 230 kV (Sherwood)
- McLoughlin 230 kV
- Keeler 230 kV (St. Marys)
- Rivergate 230 kV

- Bethel 230 kV [8]
- Troutdale 230 kV (Blue Lake)

Interconnection

For a bid to qualify for the initial short list it must have the following:

- An active generation interconnection request in the transmission provider's interconnection queue
- A completed system impact study
- If interconnection involves a 3rd party other than the transmission provider, the bid must also include an interconnection request to the 3rd party and all associated studies.

To qualify for the final short list, the Bidder must have a completed facilities study.

Bidders proposing to interconnect a resource within PGE's Balancing Authority Area will need to include all incremental costs to deliver, or sink, energy from the resource to PGE's load. Bidders can determine these costs by requesting Network Resource Interconnection Service and Network Integration Transmission Service under PGE's Open Access Transmission Tariff (OATT) from PGE's Transmission and Reliability Services Department (T&RS) or Bidders can request Energy Resource Interconnection Service and Point-to-Point Transmission Service under PGE's OATT from T&RS. Either process will enable T&RS to study whether any system upgrades are needed to accommodate transmission service for the bid. Questions concerning the various types of Interconnection and Transmission Service available under PGE's OATT should be directed to T&RS.

Transmission - Renewable Resources

To qualify for this RFP as a renewable resource, a Bidder must have an achievable plan for long-term transmission service for 80% of the interconnection limit of the facility. Short term firm services may be used for the remaining 20% of the facility's interconnection limit. Eligible long-term transmission services include long-term firm, long-term conditional firm bridge, or long-term conditional firm reassessment. For long-term transmission services, Bidders relying on BPA for transmission service are required to have either previously been granted eligible transmission service or have an eligible and active OASIS status Transmission Service Request (TSR) participating in the BPA TSR Study and Expansion Process (TSEP)[9]. The eligible transmission service must originate at the resource POR/POI and provide delivery to one of the acceptable Points of Delivery, listed above, prior to the project's Commercial Operation Date (COD). Long-term rights must match the duration of the contract term or include rollover rights.

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[8] At this time the Bethel 230 kV POD has been determined to have insufficient available capacity and is unavailable for new transmission service requests. However, Bidders that have already been granted long-term service at this POD may use this POD.
[9] See BPA TSR Study and Expansion Process Business Practice, dated 4/2/2021, available at: https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/TSR-Study-Expansion-Process-BP.pdf

PGE's evaluation process will determine if there are additional costs or risks to deliver the resource to PGE load.

If a Bidder has a TSR that utilizes Newpoint as the Point of Receipt (POR), the TSR must reference the specific Generation Interconnection Request number for the resource in the comments field.

Transmission -Dispatchable Resources

To qualify for this RFP as a dispatchable resource, a bidder must have Long-Term Firm transmission service for 100 percent of the facility's interconnection limit. Bidders relying on BPA for transmission service are required to have either previously been granted eligible transmission service or have an eligible and active OASIS status Transmission Service Request (TSR) participating in the BPA TSR Study and Expansion Process[10]. The transmission service must originate at the resource point of receipt (POR)/point of interconnection (POI) and provide delivery to one of the acceptable Points of Delivery, defined below, prior to project COD. Long-term rights must match the duration of the contract term or include rollover rights.

PGE's evaluation process will determine if there are additional costs or risks to deliver the resource to PGE load.

If a Bidder has a TSR that utilizes Newpoint as the POR, the TSR must reference the specific Generation Interconnection Request number for the resource in the comments field.

Integration

For projects located outside of PGE's Balancing Authority Area, Bidder will procure, and PGE will reimburse Bidder for all integration services from an entity, mutually agreed upon by the parties, that may be required to ensure delivery of energy as scheduled to the Delivery Point. Integration Services include, but are not limited to, generation imbalance, variable energy resource balancing service and any EIM costs associated with interconnection. Integration Services do not include ancillary service costs associated with the transmission provider's provision of firm transmission service.

Labor

Union labor must be utilized for major construction activities related to the resource and must include a Project Labor Agreement (PLA) requirement in any related executed Engineering, Procurement and Construction Agreements.

PGE requires that the labor group has policies in place that are designed to limit or prevent workplace harassment and discrimination.

[10] See BPA TSR Study and Expansion Process Business Practice, dated 4/2/2021, available at: https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/TSR-Study-Expansion-Process-BP.pdf

PGE will be asking that the labor group has policies in place that are designed to promote workplace diversity, equity and inclusion of communities who have been traditionally underrepresented in the energy sector including, but not limited to, women, veterans and Black, Indigenous and People of Color, with an aspirational goal of having at least 15 percent of the total work hours performed by individuals from those communities.

PGE requires that Bidders recognize this requirement upon bidding and affirm their commitment to meet the requirement. However, PGE does not expect a Bidder to have secured a PLA prior to contract execution with PGE as it is customary to negotiate such labor agreements closer to construction activities.

Equipment manufacturer

For agreement structures that contemplate utility ownership, all major equipment manufacturers must be PGE preferred vendors. A list of PGE's preferred vendors is supplied in Appendix M, PGE's technical specifications.

Technical specifications

For agreement structures that contemplate utility ownership, concurrent with supplying the best and final offer the Bidder must supply redlines to PGE's technical specifications.

Service agreement

For resources that contemplate a utility ownership structure, bids must include quoted vendor costs for long-term service agreements (LTSA) for a minimum of five years. For battery-energy storage resources, LTSAs must include commitments to maintain the capacity performance through augmentation or alternative mechanisms.

Usable Energy Storage Bidding

Bidders are required to bid energy storage resources on a contract capacity basis and must account separately for minimum and maximum system state of charge. PGE will only accept bids that express cost and performance on a usable state of charge basis that allows PGE to dispatch the project from a 0%-100% state of charge without commercial or performance consequence.

Contract Terms and Conditions

Utility Owned Commercial Structures

PGE invites Bidders to submit proposals for various types of asset sale and ownership transfer or service agreements. Form Asset Purchase Agreement (APA) and Engineering Procure Construction (EPC) term sheets are included in Appendix D. Form APA and EPC Agreements are included in Appendix H and Appendix I. AT THE TIME OF BID SUBMISSION, BIDDERS ARE REQUIRED TO IDENTIFY, THROUGH REDLINES, EXCEPTIONS TO ANY TERM OR CONDITION IN THE TERM SHEET. For terms the Bidder does not intend to accept, the Bidder is required to propose alternative terms and conditions in redline format to the form term sheets. Should proposed revisions to highlighted terms and conditions increase

CASE: UE 427
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 204

2021 RFP Scoring Methodology

February 6, 2024

Appendix N

Scoring and Methodology

2021 All-Source RFP

Table of Contents

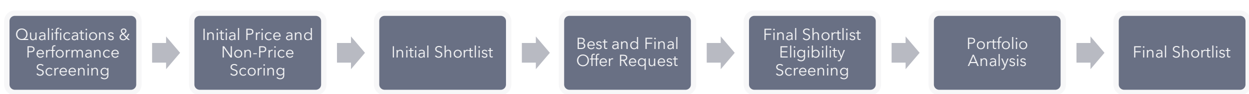
Scoring Methodology

1.1 Overall Analysis Process

PGE's evaluation and scoring process is designed to account for the unique attributes of several resource types and determine the resource portfolio that offers the best combination of cost and risk for PGE customers. PGE intends to use IRP models with select modifications to evaluate proposed resources and to work closely with the IE as they validate that the evaluation criteria, methods, models, and other processes have been applied consistently and appropriately to all bids. All proposed alterations to PGE's IRP models are discussed in detail in the analysis sections below.

The following diagram illustrates the anticipated key steps in the analysis process, and the discussion below provides additional detail on the required modeling and scoring within each step.

Figure 1: 2021 All-Source RFP Analysis Process



1.2 Qualifications & Performance Screen

PGE intends to employ a qualifications and performance screen as the first step in the RFP evaluation process. Resources that do not meet all of PGE's initial applicable requirements will not be considered for the initial short list and will not receive a price and non-price score. PGE will document why bids did not pass the qualifications and performance screen and will provide that highly confidential information upon request to Staff and docket participants that have signed a modified protective order. A description of the various qualifications is included in Table 1 below.

Table 1: Qualifications & Performance Screening Requirements

Qualifications & Performance Screening Requirements	
Entity Requirement	As applicable, entities must be authorized under the law to sell power, and able to schedule power and operate under industry standards established by the Federal Energy Regulatory Commission (FERC), Western Electricity Coordinating Council (WECC), and the North American Energy Reliability Council (NERC), or other applicable regulatory body or government agency.
Financing Requirement	As applicable, bidders must provide a reasonable plan to obtain project financing. Those bidders who are unable to internally or balance sheet finance the proposed project (supported by appropriate financial statements) must provide evidence of a good faith commitment from a financial institution or lender prior to placement on PGE's final short list.
Technology Eligibility	PGE will accept bids for resource core technologies that are commercially proven and deployed at large scales within the North American utility industry. Renewable resources bid into the solicitation must be RPS eligible. Dispatchable resources must be non-emitting technologies that can generate when called upon.
Resource Online Date	Resources must be online no later than the end of 2024, with the exception of pumped hydro, which must be online by the end of 2027.
Qualifying Product	PGE shall be the offtake for all output from the facility or portion of the facility bid into this RFP. Projects must include all power attributes including associated renewable energy credits, environmental attributes, energy benefits, and capacity benefits. Bidder is responsible for ensuring RECs are established in WREGIS.
Nameplate Requirement	Resources that are bid into this RFP must be large enough to qualify for contracting under PGE's Schedule 202 for qualifying facilities.[1] Solar resources must be larger than 3 MW and all other facilities must be larger than 10 MW. If a Bidder already has a Schedule 202 agreement with PGE, they are welcome to include such the resource subject of

[1] This requirement is consistent with OAR 860-089-0250(4).

	agreement in its bid, but PGE does not guarantee that the bidder will be excused from the existing agreement.
Term Length	PGE requires a 15-year minimum term and a 30-year maximum term for those agreements.
Tax Credit Eligibility	Renewable resources must be eligible for the federal PTC or ITC and all bids must provide a narrative on how the project will obtain the tax credits.
Credit	Bidders must meet PGE's credit eligibility thresholds. For investment grade Bidders, their long-term, senior unsecured debt must be rated BBB- or higher by Standard & Poor's and Fitch, BBB (low) or higher by DBRS, or Baa3 or higher by Moody's Investor Services, Inc. For non-investment grade Bidders, they must demonstrate, prior to final short list, that a qualified institution will secure the Bidder's performance obligations through a letter of credit or guaranty, in a form acceptable to PGE.
Site Control	Bidders must support the bid by demonstrating dependable site control, for both the location of the resource and any gen-tie path that is required. At the time of bid submission, Bidders must possess at least one of the following: • title to the site • an executed lease agreement • an executed easement • an executed option agreement applicable to a minimum of 80% of the project site The site control documents should reflect the resource type bid into this RFP. Prior to placement on PGE's final short list, bidders will be required to demonstrate site control for 100% of the project site.
Permitting	Please see the chart in Exhibit A that denotes permitting requirements for the initial short list and final short list by resource type. In the event a specific permit is not required for the resources that is bid into this RFP, the Bidder may provide a narrative explanation on the bid form regarding why it is not applicable.
Acceptable Delivery Points	PGE will accept delivery within PGE's balancing authority area and at BPAT.PGE. PGE will not accept delivery at Pelton Round Butte or at PacifiCorp West. The BPAT.PGE Point of Delivery is associated with the following substations or "sinks":

	• PGE Contiguous • Pearl 230 kV (Sherwood) • McLoughlin 230 kV • Keeler 230 kV (St. Marys) • Rivergate 230 kV • Bethel 230 kV [2] • Troutdale 230 kV (Blue Lake)
Interconnection	For a bid to qualify for the initial short list it must have the following: An active generation interconnection request in the transmission provider's interconnection queue A completed system impact study If interconnection involves a 3rd party other than the transmission provider, the bid must also include an interconnection request to the 3rd party and all associated studies. To qualify for the final short list, it must have a completed facilities study. Resources located on PGE's system must be studied as Network Resource Interconnection Service. Resources located off-system can be studied as Energy Resource Interconnection Service or Network Resource Interconnection Service.
Transmission Requirements	Renewable Resources Eligible transmission service products include: • long-term firm transmission service, • long-term conditional firm bridge, number of hours, or • long-term conditional firm reassessment, number of hours

[2] At this time the Bethel 230 kV POD has been determined to have insufficient available capacity and is unavailable for new transmission service requests. However, Bidders that have already been granted long-term service at this POD may use this POD.

	To qualify for this RFP, a bidder must have eligible transmission service described above that is equivalent to at least 80 percent of the facility's interconnection limit. The eligible transmission service must originate at the POR/POI and provide delivery to one of the acceptable points of delivery, defined above, prior to project COD. Bidders relying on BPA for transmission service are required to have either: 1) previously granted eligible transmission service, or 2) an eligible and active OASIS status Transmission Service Request (TSR) participating in the BPA TSR Study and Expansion Process. PGE's evaluation process will determine if there are additional costs or risks to deliver the resource to PGE load. If a Bidder has a TSR that utilizes Newpoint as the POR, the TSR must reference the specific Generation Interconnection Request number for the resource in the comments field. Dispatchable Resources To qualify for this RFP as a dispatchable resource, a bidder must have long term firm transmission rights for 100 percent of the facility's interconnection limit. The long-term firm transmission service must originate at the resource POR/POI and provide delivery to one of the acceptable points of delivery, defined above, prior to project COD. Bidders relying on BPA for transmission service are required to have either previously granted transmission service or an active OASIS TSR participating in the BPA TSR Study and Expansion Process. If a Bidder has a TSR that utilizes Newpoint as the POR, the TSR must reference the specific Generation Interconnection Request number for the resource in the comments field.
Integration	For projects located outside of PGE's Balancing Authority Area, PGE will determine and elect integration services necessary to ensure delivery of energy to the Point of Delivery. For a third party owned project, PGE will reimburse projects for integration services elected by PGE. Integration Services include, but are not limited to, generation imbalance, variable energy resource balancing service and any EIM costs associated with interconnection. Integration Services do not include ancillary service costs associated with the transmission provider's provision of firm transmission service.
Labor Requirement	Union labor must be utilized for major construction activities related to the resource and must include a Project Labor Agreement requirement in any related executed Engineering, Procurement and Construction Agreements. PGE requires that the labor group has policies in place that are designed to limit or prevent workplace harassment and discrimination.

	PGE will be asking that the labor group has policies in place that are designed to promote workplace diversity, equity and inclusion of communities who have been traditionally underrepresented in the renewable energy sector including, but not limited to, women, veterans and Black, Indigenous and People of Color, with an aspirational goal of having at least 15 percent of the total work hours performed by individuals from those communities. PGE requires that bidders recognize this requirement upon bidding and affirm their commitment to meet the requirement. However, PGE does not expect a bidder to have secured a PLA prior to contract execution with PGE as it is customary to negotiate such labor agreements closer to construction activities.
Accepted equipment manufacturers for utility owned	All major equipment manufacturers must be PGE preferred vendors.
Reasonable adherence to PGE technical specifications for utility ownership structures	Concurrent with supplying the best and final offer, all bids that contemplate a utility ownership structure must provide redlines to PGE's technical specifications.
Service agreement requirements for utility ownership structures	Utility-owned resources must include quoted vendor costs for long--term service agreements (LTSA) for a minimum of five years. For battery-energy storage resources, LTSAs must include commitments to maintain the capacity performance through augmentation or alternative mechanisms.

1.3 Scoring Methodology

Consistent with the Commission's CBRs all bids that pass PGE's qualifications and performance screen will be scored and ranked based on price and non-price factors. Price scores will be based on prices submitted by bidders, the forecasted performance of the resource, and the associated real-levelized cost and benefit of the bid. Non-price scores will focus on commercial and economic risks that a bidder elects to transfer to PGE and our customers through proposed modifications to form contract term sheets as well as certain bid attributes further detailed in the non-price scoring section.

1.3.1 Price and Non-Price Weightings

Each bid will be scored based on a combination of price and non-price points. PGE will allocate 70 percent of available bid points to bids based on the price and performance considerations reflected in the price score. PGE will allocate30 percent of the available bid points to bids based on non-price factors that cannot be readily converted into minimum bidder requirements. As is required in OAR 860-89-0400(5)(b)(A), additional sensitivities will be performed when developing the initial and final short lists that evaluate how bids perform under a 80/20 and 60/40 price and non-price weighting sensitivities. A matrix that details the allocation of price and non-price points for each resource type is included in Exhibit B.

The purpose of non-price scoring is to acknowledge the important benefits and risks associated with a proposed project that cannot be practically expressed in a bid's price. As is permitted under OAR 860-089-0400(2)(b), PGE's non-price scoring is largely based on conformance to proposed standard form contracts and term sheets. Additional non-price scoring criteria must be objective and reasonably subject to self-scoring by bidders.

1.3.2 Price Scoring

PGE's price scoring will utilize models and methodologies consistent with the 2019 IRP and IRP Update process. Revenue requirement modeling will determine the bid cost, AURORA will be used to calculate energy values, Sequoia will be used to determine the capacity value, and results from ROM will provide flexibility value assessments. Some of these models required modifications for RFP evaluation purposes. Those modifications are further detailed in each section below.

Bid Cost Determination

A bid's cost reflects the total cost, fixed and variable, associated with the project's delivery of energy, capacity, and ancillaries at its forecast economic dispatch. PGE will utilize a revenue requirement model in Excel over the economic life of the asset to calculate the total offer cost, expressed on a present-value basis. A real levelized net present value is the value that when escalated at the annual inflation rate, has the same net present value as the original total offer cost. The model will consider the unique fixed and variable costs associated with each resource.

For bids that contemplate a power purchase agreement, a bid's fixed cost will include (if applicable) all forecast fixed payments, capacity charges, wheeling costs, integration costs, ancillary services, and PGE system upgrade costs. Variable costs for power purchase agreements will include all energy payments, additional variable O&M costs, line losses, emission costs passed onto the buyer, and start-up charges, if applicable. PGE will determine the magnitude of a bid's variable costs by the bid's simulated dispatch against forecast market prices developed using the Aurora modeling, forecasting, and analysis software.

For bids that contemplate a utility ownership structure, a bid's fixed costs will include total depreciation, salvage, return, income taxes, deferred income taxes, deferred tax asset costs, property taxes, fixed operating and maintenance costs (O&M), wheeling charges, and ancillary services less any tax credit benefits. A bid's variable costs will include all fuel costs, variable O&M, emissions costs, start-up costs less any PTC benefit.

To evaluate bids containing different resource characteristics on a comparable basis, prices submitted by the Bidder may be subject to adjustments, and adjustments may also be required throughout the evaluation process. For consistency PGE intends to assess all bids the BPA reserves rate. Renewable resources will be assessed BPA's variable energy resource balancing services, and dispatchable resources will be assessed dispatchable energy resource balancing services. Examples of other adjustments include applying applicable interconnection costs captured in interconnection facilities studies, adjusting for ancillary service rate changes, altering assumed project costs based on redlines to technical specifications, and performance assurance adjustments if the Bidder takes exception to the required performance assurances for before and after the commercial operation date.

Energy Value Determination

An offer's energy value reflects the value of energy generated throughout the offer's economic life or term. To calculate the energy value, PGE will forecast resource production and utilize the reference case market price forecast from the 2019 IRP Update, inclusive of available natural gas price forecast updates. The production value will be based on bidder provided generation information, and in the instance of storage resources, PGE will simulate resource dispatch using the Aurora production cost simulation tools deployed in the IRP. Energy value for the duration of the offer's term is expressed on a present-value basis, levelized using annuity methods, and included in the offer's total levelized value. To evaluate energy value risks, PGE will conduct energy value sensitivities using multiple price curves within portfolio analysis.

Capacity Value Determination

PGE is facing an upcoming capacity deficit in 2025 and requires capacity products to otherwise displace the need to contract with or construct new generating facilities. Individual resource capacity values will be calculated as the product of the bid's capacity contribution and the avoided capacity cost. PGE's avoided capacity cost will utilize the real-levelized cost, net of wholesale revenues and flexibility value, adjusted for effective load carrying capability (ELCC) of a simple-cycle combustion turbine (SCCT) as depicted in the 2019 IRP Update. For additional perspective, PGE will also use the average cost of dispatchable capacity from bids in this RFP as a proxy for avoided capacity cost.

Individual capacity contributions will be calculated using Sequoia. Sequoia is a loss--of--load probability model that assesses both capacity need and capacity contribution of potential incremental resources. The model uses a Monte Carlo module to construct thousands of plausible weeks of load and resource conditions. It then evaluates these weeks independently in a dispatch module that optimizes the generation from dispatchable resources across all hours of the week to minimize the reliability objective function (i.e., minimize the sum of the average unserved energy across the week and the maximum unserved energy experienced in a single hour during the week).

The model has an Excel interface with a Python and GAMS back end. It also requires a license to the Gurobi solver to achieve adequate performance. Further details on Sequoia were included in Appendix K of the 2019 IRP Update.

Since the 2019 IRP Update, PGE has identified necessary modeling changes and improved Sequoia to allow for direct modeling of the diverse commercial bids expected to bid into the 2021 All-Source RFP. The Sequoia changes include the following:

- Load update – PGE updated Sequoia to include the most recent econometric load forecast which was conducted in March of 2021.
- Contracts update – PGE will update Sequoia to include the appropriate snapshot of PURPA qualifying facilities and bi-lateral contracts.
- Hybrid resource dispatch – PGE updated Sequoia to enable more accurate hybrid resource representation. The changes allow PGE to model DC-coupled storage paired with DC and/or

AC generation as well as AC-coupled storage paired with DC and/or AC generation. The updated functionality replaced the earlier hybrid dispatch module, which was a simplified AC storage paired with AC generation.

- Disaggregation of hybrid resource dispatch – Sequoia now allows for hybrid resources to be treated as separate resources for dispatch. This also improves the modeling for storage resources, which were previously aggregated for the storage dispatch module.
- Storage cycling limitation – PGE introduced functionality to reflect any daily cycling limitations, if commercially applicable.
- Hourly transmission curtailments – Sequoia can include assumed hourly curtailments based on the type of transmission product the resource is planning to use.

As discussed above, PGE will evaluate multiple transmission products as part of this RFP. Depending on the product selected, PGE will adjust the capacity value of the resource to account for the product's reliability, which is described in more detail in the chart below.

Table 1: Impacts to Capacity Value Based on Transmission Products

Impacts to Capacity Value Based on Transmission Products	
Long-Term Firm	• When determining capacity contribution, the maximum facility output will be limited to the quantity of long-term firm rights (no less than 80% of interconnection limit). • No capacity value will be attributed to the portion of the resource's interconnection limit that is relying on short-term firm, if any.
Conditional Firm Bridge	• When determining capacity contribution, the maximum facility output will be limited by the amount of conditional firm bridge rights (no less than 80% of interconnection limit). • For the purposes of capacity contribution calculations, generation delivered by condition firm bridge will be assumed to be curtailed. Specifically, resources on conditional firm bridge will also have their output curtailed for 50% of annual curtailment hours as identified and reserved for use by BPA. The model will assume that these curtailments happen during PGE's approximate times of highest need. Upon the forecasted completion of transmission upgrades necessary to convert conditional firm bridge service into long term firm service, a resource's forecasted curtailment conditions will be removed.3 If BPA's cluster study results are not available to indicate the maximum number of curtailed hours, PGE will use the average assessed hours from the previous study. • No capacity value will be attributed to the portion of the resources facility's interconnection limit that is relying on short term firm, if any.

[3] LC 73, 2019 IRP reply comments at 85, see figure 15, available at: https://edocs.puc.state.or.us/efdocs/HAC/lc73hac153345.pdf

Conditional Firm Reassessment	• Due to the unpredictable long-term nature of this product as discussed in the transmission section above, PGE will not attribute any capacity value to bids relying on conditional firm reassessment.

Flexibility Value Determination

Flexibility value was new in PGE's 2019 IRP and was included to estimate the value a resource brings to PGE's portfolio by responding to forecast errors, enabling fast ramping, and meeting reserve requirements. PGE estimated these values using PGE's Resource Optimization Model (ROM). ROM is a multi-stage optimal commitment and dispatch model that accounts for the operational impacts of forecast errors, operating constraints based on commitment decisions with imperfect information, gas constraints, and operating reserves (load following, regulation, spinning, and non-spinning reserves). It ensures that the system can respond to short time-scale variability of load and renewables as well as contingency events and is implemented using the General Algebraic Modeling System (GAMS) programming and a Gurobi Optimizer4.

For resource flexibility values in the 2021 All-Source RFP, PGE will rely on flexibility values from ROM as detailed in the 2019 IRP. These values will be adjusted based on the size of each resource evaluated. For combined solar and storage projects, PGE will give a battery storage project its full flexibility value if it is able to charge from the grid after it has been online for five years. Due to ITC eligibility requirements, solar and storage resources generally cannot rely on grid charge for the five years following a project's online date. Below are the flexibility values for 100 MW resources included in the 2019 IRP.

Table 2: Flexibility Value from the 2019 IRP

Flexibility Value (2020$/kW-yr)	
2-hour Battery	$23.73
4-hour Battery	$28.10
6-hour Battery	$29.43
Pumped Storage	$25.95

Offer Price Value-to-Cost Evaluation

PGE will evaluate all Renewable RFP bids against a value-to-cost binary metric. The value-to-cost metric evaluates whether a project's costs are exceeded by a project's forecasted value under Reference Case

[4] For a more detailed description of ROM, please consult Appendix I.5 in PGE's 2019 IRP at 358-359.

conditions considering only the resource's forecasted energy, capacity, and flexibility values. Offers will be considered to have a 'True' value-to-cost metric if the resource's forecasted levelized benefit exceeds their forecasted levelized cost. The formula below illustrates how the metric will be assessed for renewable bids.

Renewable Resources' Value-to-Cost Binary Metric is True if:

$$Levelized\ Resource\ Cost < Levelized\ Energy\ Value + Levelized\ Capacity\ Value + Levelized\ Flexibility\ Value$$

The value-to-cost evaluation will be unique for each resource evaluated by PGE and will elevate resources that provide more value to PGE customers due to the resource's generation profile. For this reason, it is possible that a lower-priced resource will not pass the economic evaluation while a higher-priced resource will pass the economic evaluation due to increased resource value, such as by providing higher capacity contribution or more valuable energy production.

Allocation of Price Score Points

Once the cost of each bid is determined it will be netted against the levelized energy, capacity, and flexibility value associated with the bid. This net cost will be expressed in real levelized $/MWh for renewable bids and real levelized $/kw-mo for dispatchable bids. Each bid's component cost and benefits will be converted into a cost-to-benefit price score ratio. Price scoring points will be allocated on a scaled basis, with 700 points allocated to the best price ratio. The allocation system is illustrated by the example below.

Table 3: Price Score Point Allocation Example

Price Score Point Allocation Example					
A	**B**	**C**	**D**	**E**	**F**
	Total Cost	Total Value	Ratio of Cost to Benefit	Lowest Ratio	Points
			B/C	Min(D)	700*(E/D)
Bid 1	40	50	0.8	0.73	638
Bid 2	35	48	0.73	0.73	700
Bid 3	15	20	0.75	0.73	681
Figures are fictitious and for example purposes only					

1.4 Non-Price Scoring

Non-price scoring is designed to reflect the commercial and performance risks and benefits associated with the project that is not captured in the offer's price score. Non-price scoring will be assigned 300 points. Scores for dispatchable resources will be based on commercial performance risk and COD related risks. Scores for renewable resources will be based on commercial performance risk, transmission plan attributes and level capacity ratio score (based on a ratio of a resource's capacity contribution to MWa). PGE will first calculate the non-price score for the initial short list, and then will calculate a second non-price score in the portfolio analysis stage based on the resources in each portfolio.

Commercial Performance Risks

Commercial performance risks will be assessed based on bidder proposed modifications to form agreement term sheets and additional bid materials that inform identified commercial risk provisions. Please refer to Appendix A: Renewable Resource Form Term Sheet, Appendix B: Storage Capacity Form Term Sheet, Appendix C: Hybrid Resource Form Term Sheet, and Appendix D: APA & EPC Form Term Sheets. Bidder term sheet commitments are important and consequential as they are the primary indicator of a bidder's commitment to deliver on bid specifications and limit the transference of risk onto PGE and its customers. Two-hundred Twelve (212) non-price points for dispatchable and renewable resources will be based on the scoring of commercial performance risk reflected in the term sheets and associated documents. Bidders are required to review PGE form term sheets and mark any exceptions to those term sheet agreements. Modified term sheets will be the foundation for negotiations with successful bidders. In addition, form agreements are also included for reference and further characterize the terms and conditions that PGE expects to initiate its negotiations preceding contract execution. In contrast to form term sheets, Bidders are not required to mark-up the from agreements. BIDDERS THAT CHOOSE NOT TO PROVIDE REDLINES AND DEFER COMMERCIAL COMMITMENTS UNTIL NEGOTIAION PHASE WILL NOT RECEIVE COMMERICAL PERFORMANCE RISK NON-PRICE POINTS. The specific commercial performance scoring rubric relied upon to guide PGE's scoring is included in Exhibit C.

Characteristics that PGE will consider in commercial performance risk non-price scoring include the following:

- Resource performance guarantees – adherence to provisions including scheduling commitments, forecasting commitments, remedies of non-performance, security, credit support, warranties, service agreements, and output, availability factor, and/or performance guarantees will determine the allocation of 106 non-price points for dispatchable and renewable resources.

- Limitations of liability and remedies – adherence to provisions including commercial online date guarantees, force majeure, settlement, indemnification, default, and termination, will determine the allocation of 106 non-price points for dispatchable and renewable resources.

Transmission Plan Attributes

PGE will also assess how the transmission plan for each renewable resource introduces additional risk to PGE's portfolio; 25 points will be included in this score. Bidders that propose to rely on greater quantities of short-term firm service introduce long term risks to PGE that cannot be adequately accounted for in price scoring. As enumerated in the table below, points will be awarded to offers that have a lower risk of service associated with more of the facility's potential output delivered with long-term transmission rights.

Table 4: Non-Price Score Allocation Based on Transmission Plan

	Max Score	Weight	Total Points	Point Allocation
Long term transmission product reservation	4	7.25	29	4 - 100% of facility's interconnection limit 3 - 95% of facility's interconnection limit 2 - 90% of facility's interconnection limit 1 - 85% of facility's interconnection limit 0 - 80% of facility's interconnection limit

Level Capacity Ratio

For renewable resources, PGE proposes to employ non-price scoring metric that favors renewable resources that offer higher capacity contributions with lower annual energy output. The level capacity ratio metric will be calculated in accordance with the formula below. This metric allocates the remaining non-price points for renewable resources to those resources that have a high capacity contribution compared to the energy that they generate as depicted below:

$$\frac{ELCC\ (Measure\ of\ Capacity\ Contribution)}{MWa\ (Measure\ of\ Energy)} \times 59\ Non - Price\ Points$$

- This metric intentionally favors resources that best support reliability while recognizing PGE's portfolio energy load-resource-balance limitations.

Online Date Certainty

Given that PGE has short-term capacity needs and that the future availability of short-term and medium-term dispatchable resource contracts is challenging to forecast, PGE will attribute non-price points to dispatchable resources that have an earlier COD. Renewable resources are already incentivized to have the earliest COD possible due to the timelines associated with PTCs and ITCs. The impact of those tax credits is captured in the offer price. The table below illustrates how points will be awarded to dispatchable resources that offer earlier capacity value to PGE:

Table 5: Non-Price Score Allocation for Dispatchable Resources based on Commercial Operation Date

	Max Score	Weight	Total Points	Point Allocation
Non-Price Score Allocation based on Commercial Online Date	5	17.6	88	5- COD by 12/31/2023 4 – COD by 12/31/2024 0 – COD after 12/31/2024

1.5 Best and Final Offer Request & Final Short List Eligibility Screening

Initial short list candidates will be contacted by PGE and requested to provide their best and final offer. PGE will also ask that they redline technical specifications (if they have not already done so) and provide updates on pricing, permitting processes, interconnections studies, and the cluster study process. This new information will be evaluated to ensure the bid meets the eligibility requirements for the final short list, and all relevant updates will be incorporated into the portfolio analysis.

1.6 Portfolio Analysis

Consistent with the methodology in PGE's 2019 IRP and 2019 IRP Update, PGE will utilize ROSE--E for portfolio analysis for this RFP. ROSE-E is a portfolio analysis tool that generates optimal portfolios according to a specified objective. In doing so, ROSE-E creates various cost and risk metrics that enable comparison across portfolios. For this RFP, ROSE-E will forecast the long--term economic performance of bids, both in isolation as well as when combined, allowing a comprehensive evaluation of bids that ensures the final short list is in the best long-term interests of customers. ROSE-E was extensively described and vetted in LC 73; for a full description of the model's construction and functionality please refer to PGE's 2019 IRP.5 While the core of ROSE--E remains in this RFP, several important changes have been made to the model to answer questions relevant to this specific setting.

ROSE-E's capacity expansion will be set to meet the carbon reduction targets established in House Bill (HB) 2021. In an IRP setting, ROSE-E ensures the system remains capacity adequate and in compliance with policy mandates by determining the optimal size and timing of additions from a list of proxy resources available to PGE.6 However, in this RFP energy additions will be limited to one proxy renewable resource (SE Washington wind), and capacity additions will be limited to the capacity fill resource.7 Doing so allows ROSE-E to evaluate individual bids and combinations of bids in the context of PGE's pathway to meet HB2021's targets. However, this analysis will produce only a cursory view of the resource additions necessary to comply with HB2021; the next IRP will produce a more developed and nuanced view of the most optimal resource expansion pathway for the Company.

In this analysis ROSE-E will only use the main objective function (minimizing long-term costs).8 The benefits from each bid/combination (energy and flexibility) and costs (variable and fixed) will be direct inputs into the model, along with the key financial parameters, price forecasts, and resource generation. The capacity value brought by each bid/combination will be reflected in reductions in capacity need, calculated in PGE's capacity model Sequoia. With these, PGE will calculate the traditional scoring metrics used in the 2019 IRP and IRP Update. PGE is also committed to work with Staff to determine the most informative approach to examine a low wholesale market price sensitivity as well as a PTC extension sensitivity and will share all sensitivity analyses with the independent evaluator for their review.

Once PGE determines the portfolio values for various combinations of bids that are examined in ROSE-E, PGE will convert the traditional metrics into a price score. PGE will also generate a non-price score for each resource combination based on the latest non-price scoring information. If a portfolio consists of multiple resources, PGE will weigh the various non-price scores for each resource in a portfolio based on the lesser of the MW nameplate size or the interconnection limit for the resource. Finally, PGE will also calculate multiple portfolio scores that examine multiple price score and non-price score weighting structures.

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[5] See 2019 IRP, Appendix I.6 ROSE-E – PGE's Portfolio Optimization Tool at 359, available here: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=lc73haa162516.pdf&DocketID=21929&numSequence=37
[6] Proxy resources used in the 2019 IRP included four wind, four natural gas, three battery storage, solar, solar plus storage, pumped storage, geothermal, and biomass resource options.
[7] Described in the 2019 IRP, the Capacity Fill resource is a technology-agnostic resource that provides capacity priced just over the avoided cost resource
[8] The other three objective functions (minimize short-term cost, minimize variability, and minimize GHG & cost) were only used for select optimized portfolios in the 2019 IRP.

1.7 Final Short List

Upon completion of the portfolio analysis, PGE will examine the total combined price and non-price scores to determine the best combination of cost and risk for PGE customers. These results will be used to determine PGE's final short list, which, if acknowledged, will be the group of resources that PGE will make selections from. Once the final short list is filed, PGE will engage in negotiations with those selected bidders. The selected IE will issue its closing report two weeks after PGE has filed the final short list of bids.

Exhibit A: Required Permits

Permits/Studies	Required By						
	Wind	Solar	Geothermal	Hydro / Pumped Storage	Energy Storage (Batteries)	Biomass	Hydrogen/ Other
State permit (e.g., site certificate)	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist
Local land use permit (e.g., conditional use permit)	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist
FERC License (or final EIS from FERC)	n/a	n/a	n/a	Bid	n/a	n/a	n/a
Federal siting permit (e.g., NEPA Record of Decision for construction*) *This does not include NEPA for an Eagle Take Permit*	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist	Final Shortlist
Air quality permit (e.g., ACDP, etc.)	n/a	n/a	n/a	n/a	n/a	Final Shortlist	n/a
FCC permit	Construction	Construction	Construction	Construction	Construction	Construction	Construction
FAA permits	CP	CP	CP	CP	CP	CP	CP
Airspace and Obstacle Evaluation Analysis	Bid	n/a	n/a	n/a	n/a	n/a	n/a
Water rights	n/a	n/a	Bid	Bid	n/a	Bid	Bid
Wastewater discharge permit (e.g., NPDES, WPCF, etc.)	n/a	Final Shortlist	Final Shortlist	n/a	n/a	Final Shortlist	Final Shortlist
Construction Permits (e.g., NPDES-1200C, building permit, site development permit, etc.)	Construction	Construction	Construction	Construction	Construction	Construction	Construction
Removal Fill Permits (wetland and in-water work, e.g., State, Army Corps)	Construction	Construction	Construction	Construction	Construction	Construction	Construction
Eagle surveys and take estimates: provide available survey data, a well justified preliminary take estimate, and a detailed schedule for completing surveys and final take estimate per USFWS-approved protocols	Bid	Bid	Bid	Bid	Bid	Bid	Bid
Federal ESA surveys: provide comprehensive project-wide survey results (this does not include any final pre-construction follow-up surveys, such as may be required in a site certificate or other project authorization, for the purpose of micro-siting and defining boundaries of and avoiding active occupied habitat in a given construction year)	Bid	Bid	Bid	Bid	Bid	Bid	Bid
State/local sensitive species surveys: provide comprehensive project-wide survey results (this does not include any final pre-construction follow-up surveys, such as may be required in a site certificate or other project authorization, for the purpose of micro-siting and defining boundaries of and avoiding active occupied habitat in a given construction year)	Bid	Bid	Bid	Bid	Bid	Bid	Bid
Cultural resource surveys started (at a minimum, contracted with a cultural resources consultant)	Bid	Bid	Bid	Bid	Bid	Bid	Bid
Tribal coordination initiated (started consultation with area tribes to discuss Traditional Use Studies, Traditional Cultural Properties, and other relevant studies)	Bid	Bid	Bid	Bid	Bid	Bid	Bid
Demonstrate a realistic timeline for procuring any additional permits, licenses, or assessments required to start construction	Bid	Bid	Bid	Bid	Bid	Bid	Bid

Key:
Bid - Must be obtained by bid submittal date
Final Shortlist - Must be obtained by bid Final Shortlist date
Construction - Must be obtained by start of construction
CP - Must be approved as a condition precedent in the definitive agreemer
n/a - Not applicable

Exhibit B: Point Allocation Matrix

Score Type	Component	Description	Total Dispatchable Resource Points Possible	Total Renewable Resource Points Possible
Price Score	N/A	Points are allocated based on a cost to benefit ratio	700	700
Non-Price Score	Commercial Performance Risk	Points are allocated based on adherence to commercial terms and conditions that focus on performance guarantees and limitations of liability and remedies	212	212
	Transmission Plan Attributes	Points are allocated based on the facility's potential output met with long-term transmission rights	N/A	29
	Level Capacity Ratio	Points are allocated based on the ratio of the resource's capacity contribution to its expected energy production	N/A	59
	Online Date Certainty	Points are allocated based on the online date of the resource	88	N/A

Exhibit C: Commercial Performance Risk Non-Price Scoring Matrix

RESOURCE PERFORMANCE GUARANTEE SECTION			
	Max Score	Point Allocation	Key Terms, Conditions, and Circumstances to Consider
Forecasting & Scheduling	35	35 = Term sheet redlines and related commercial circumstances better protect PGE customers from schedule, performance or cost risk than form term sheet provisions 28 = Term sheet redlines and related commercial documents generally conform to form term sheet and present modest risk to schedule, performance or cost. 21 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is reasonably bound by commercial term or circumstance. 14 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is not reasonably bound by commercial term or circumstance. 7 = Term sheet redlines and related commercial documents present compounded and significant risks to schedule performance or cost. Risk is not reasonably bound by commercial term or circumstance. 0 = Term sheet redlines and related commercial documents present unacceptable and unmitigated risks to schedule performance or cost. 0 = Bidder does not provide any redlines, declines to negotiate definitive agreement consistent with redlined or unedited term sheet, and/or defers all commercial considerations to negotiation phase.	• Forecasting • Scheduling • Forecast Agent • Discharge Schedule Provisions • eTag Modification • Entity • Failure to Deliver Facility Output
Credit & Security	35	35 = Term sheet redlines and related commercial circumstances better protect PGE customers from schedule, performance or cost risk than form term sheet provisions	• Security • Parent Guarantee • Credit Support

		28 = Term sheet redlines and related commercial documents generally conform to form term sheet and present modest risk to schedule, performance or cost. 21 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is reasonably bound by commercial term or circumstance. 14 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is not reasonably bound by commercial term or circumstance. 7 = Term sheet redlines and related commercial documents present compounded and significant risks to schedule performance or cost. Risk is not reasonably bound by commercial term or circumstance. 0 = Term sheet redlines and related commercial documents present unacceptable and unmitigated risks to schedule performance or cost. 0 = Bidder does not provide any redlines, declines to negotiate definitive agreement consistent with redlined or unedited term sheet, and/or defers all commercial considerations to negotiation phase.	• Aggregate Limitation of Liability
PPA and SCA Output Guarantee (Note: Bidder to receive score for either PPA and SCA Output Guarantee **or** Utility Owned Asset Output Guarantee)	35	35 = Term sheet redlines and related commercial circumstances better protect PGE customers from schedule, performance or cost risk than form term sheet provisions 28 = Term sheet redlines and related commercial documents generally conform to form term sheet and present modest risk to schedule, performance or cost. 21 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is reasonably bound by commercial term or circumstance. 14 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is not reasonably bound by commercial term or circumstance. 7 = Term sheet redlines and related commercial documents present compounded and significant risks	• Output Guarantee • Minimum Availability Guarantee • Capacity Guarantee • Duration Guarantee • Round Trip Efficiency Guarantee • Related Default Provisions • Related Damages and Remedies • Operations and Maintenance

		to schedule performance or cost. Risk is not reasonably bound by commercial term or circumstance. 0 = Term sheet redlines and related commercial documents present unacceptable and unmitigated risks to schedule performance or cost. 0 = Bidder does not provide any redlines, declines to negotiate definitive agreement consistent with redlined or unedited term sheet, and/or defers all commercial considerations to negotiation phase.	
Utility Owned Asset Output Guarantee (Note: Bidder to receive score for either PPA and SCA Output Guarantee **or** Utility Owned Asset Output Guarantee)	35	35 = Term sheet redlines and related commercial circumstances better protect PGE customers from schedule, performance or cost risk than form term sheet provisions ***and specifically include robust warranties and LTSA for asset life.*** 28 = Term sheet redlines and related commercial documents generally conform to form term sheet and present modest risk to schedule, performance or cost ***and specifically include robust warranties and LTSA.*** 21 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is reasonably bound by commercial term or circumstance. 14 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is not reasonably bound by commercial term or circumstance. 7 = Term sheet redlines and related commercial documents present compounded and significant risks to schedule performance or cost. Risk is not reasonably bound by commercial term or circumstance. 0 = Term sheet redlines and related commercial documents present unacceptable and unmitigated risks to schedule performance or cost. 0 = Bidder does not provide any redlines, declines to negotiate definitive agreement consistent with redlined or unedited term sheet, and/or defers all commercial considerations to negotiation phase.	• Warranties • Long-Term Service Agreements • Energy or Capacity Guarantees • Consideration of Utility Customer Fixed Price and Fixed Volume Guarantees Through Regulatory Model

LIMITATION OF LIABILITY AND REMEDIES

	Max Score	Point Allocation	• Key Terms, Conditions, and Circumstances to Consider
Commercial Online Date Provisions		35 = Term sheet redlines and related commercial circumstances better protect PGE customers from schedule, performance or cost risk than form term sheet provisions 28 = Term sheet redlines and related commercial documents generally conform to form term sheet and present modest risk to schedule, performance or cost. 21 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is reasonably bound by commercial term or circumstance. 14 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is not reasonably bound by commercial term or circumstance. 7 = Term sheet redlines and related commercial documents present compounded and significant risks to schedule performance or cost. Risk is not reasonably bound by commercial term or circumstance. 0 = Term sheet redlines and related commercial documents present unacceptable and unmitigated risks to schedule performance or cost. 0 = Bidder does not provide any redlines, declines to negotiate definitive agreement consistent with redlined or unedited term sheet, and/or defers all commercial considerations to negotiation phase.	• Guaranteed COD • Delay Damages • Test Energy • Progress Reports • Force Majeure • Conditions Precedent • Commercial Contingencies • Interconnection Transmission Study and Contract
Payment and Settlement Provisions		35 = Term sheet redlines and related commercial circumstances better protect PGE customers from schedule, performance or cost risk than form term sheet provisions 28 = Term sheet redlines and related commercial documents generally conform to form term sheet and present modest risk to schedule, performance or cost.	• Assumed Liabilities • Excess Energy • Curtailment • Negative Price Event • Settlement Netting Provisions

		21 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is reasonably bound by commercial term or circumstance. 14 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is not reasonably bound by commercial term or circumstance. 7 = Term sheet redlines and related commercial documents present compounded and significant risks to schedule performance or cost. Risk is not reasonably bound by commercial term or circumstance. 0 = Term sheet redlines and related commercial documents present unacceptable and unmitigated risks to schedule performance or cost. 0 = Bidder does not provide any redlines, declines to negotiate definitive agreement consistent with redlined or unedited term sheet, and/or defers all commercial considerations to negotiation phase.	• Termination Payment • Payment Schedule • Consideration of Utility Customer Fixed Price and Fixed Volume Guarantees Through Regulatory Model
Product Definition and Other Limitations		35 = Term sheet redlines and related commercial circumstances better protect PGE customers from schedule, performance or cost risk than form term sheet provisions 28 = Term sheet redlines and related commercial documents generally conform to form term sheet and present modest risk to schedule, performance or cost. 21 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is reasonably bound by commercial term or circumstance. 14 = Term sheet redlines and related commercial documents present isolated significant risks to schedule, performance or cost. Risk is not reasonably bound by commercial term or circumstance. 7 = Term sheet redlines and related commercial documents present compounded and significant risks to schedule performance or cost. Risk is not reasonably bound by commercial term or circumstance.	• Product Definitions • Third Party Sales • Commercial Transmission Risk • Control Area Services • Work to be Performed

		0 = Term sheet redlines and related commercial documents present unacceptable and unmitigated risks to schedule performance or cost. 0 = Bidder does not provide any redlines, declines to negotiate definitive agreement consistent with redlined or unedited term sheet, and/or defers all commercial considerations to negotiation phase.	

CASE: UE 427
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Interim Transmission Solution

February 6, 2024

Portland General Electric Company
Legal Department
121 SW Salmon Street • 1WTC1301 • Portland, Oregon 97204
Telephone 503-464-8544 • Facsimile 503-464-2200
portlandgeneral.com

Erin E. Apperson
Assistant General Counsel

August 30, 2019

Via Email

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, OR 97308-1088

Re: LC 73 – PGE's 2019 IRP Addendum – Interim Transmission Solution

Attention Filing Center:

Enclosed for filing today, please find PGE's 2019 IRP Addendum – Interim Transmission Solution.

PGE plans to work with Staff and intervenors to establish a process to provide comments and participate in a workshop specifically focused on the proposed interim transmission solution. PGE believes that this process should occur concurrently with the existing 2019 IRP schedule to ensure adequate opportunity for stakeholder involvement.

Thank you in advance for your assistance.

Sincerely,

Erin E. Apperson
Assistant General Counsel

EEA:dm

Enclosure

Integrated Resource Plan

AUGUST 2019

Addendum to PGE's 2019 Integrated Resource Plan
Interim Transmission Solution

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Contents

1 Introduction

The development and planned growth of renewable resources in the Northwest requires changes to the transmission system, in terms of both transmission development and utilization. Portland General Electric (PGE or Company) recognizes that the 2019 Integrated Resource Plan (IRP) renewable action provides an opportunity for the Company to contribute to continued learning about transmission utilization for renewable resources in the region. To support the 2019 IRP renewable action, PGE reassessed how the Company considers transmission within renewable procurement processes. In doing so, PGE weighed the cost and risk impacts to both customers and PGE, ensuring the proper balance between reliable deliveries of clean energy and continued renewable development. This is especially important during a period of changing regional policies and developing markets, where the challenges associated with the economical and reliable delivery of capacity and energy to serve customer needs are becoming increasingly complex.

Through careful consideration, comments provided by stakeholders, and discussions with regional partners, PGE developed a provisional program framework for its interim solution allowing for controlled learning, proper identification and allocation of risks and costs, and the ability to adjust or refine over time. The Company believes this proposal advances the utilization of the transmission system and enables least-cost and least-risk actions that provide value and clean energy to our customers and the region. This addendum presents the details of PGE's proposed provisional program and identifies how the program would be applied in the 2020 Renewable Request for Proposals (RFP).

Looking forward, PGE believes that continued development of renewables in the region will be necessary to implement clean energy policies and to meet greenhouse gas goals. Supporting this development while meeting PGE's commitments to customers will require broader transmission solutions that address both development and reliability concerns while being sufficiently flexible to adapt to changing landscapes. PGE is committed to furthering long-term, holistic solutions that enable continued renewable development to benefit customers, while appropriately addressing potential risks to both customers and PGE.

2 Background

In previous renewable RFPs, Bidders with projects outside PGE's service territory were required to provide achievable plans for acquiring long-term firm transmission service prior to the commercial operation date (COD). Bidders' transmission plans were also required to demonstrate long-term firm transmission service, in MWs, at an amount equal to the full nameplate rating of the proposed renewable resource. In some cases, conditional firm bridge was allowed to substitute for long-term firm, provided it converted to long-term firm within a pre-defined period.

Prior to filing the 2019 IRP, PGE held several stakeholder workshops and invited comments from stakeholders regarding the draft content and analysis of the 2019 IRP. Several parties provided feedback on transmission in the context of the IRP and a 2020 Renewable RFP. In the 2019 IRP, the Company acknowledged these comments and concerns by indicating it was working toward an interim solution, and identified several design principles to apply to developing such a solution:[1]

- Enable a fair, transparent, and competitive renewable resource procurement process
- Provide reasonable assurances of delivery, project success, and value to customers
- Adequately identify and mitigate potential cost shifts to customers and PGE
- Adequately identify and mitigate potential risk shifts to customers and PGE
- Appreciate differences between dispatchable and variable resources as appropriate

PGE used the above design principles and the guiding concept of a "comprehensive approach" to develop the provisional program.

3 Program Summary

As an interim solution, PGE is proposing a five-year provisional program that applies to renewable resource procurement processes conducted between 2019 and 2024.[2] The key elements of the program are:

- Applicable only to newly procured variable renewable resources pursuant to an IRP Action Plan or in support of voluntary renewable programs
- Eligible transmission service consists of one or a combination of the following products:[3]
    1. Long-Term Firm (LTF) transmission service
    2. Conditional Firm Bridge (CFB) transmission service with a Number of Hours curtailment option[4]
    3. Conditional Firm Reassessment (CFR) transmission service with a Number of Hours curtailment option[5]
- Eligible transmission service for at least 80 percent of the maximum output of the facility[6]
- PGE continues to require that output be delivered to PGE's system

[1] *See* PGE's 2019 IRP at 216.
[2] The provisional program will apply to renewable resources procured during this five-year period. In order to ensure that delivery requirements do not change during the life of the resource, the terms of this program will apply for the life of the resources procured during the five-year period.
[3] Conditional Firm Transmission Service is a type of Long-Term Firm transmission service for which there is a specified Number of Hours per year or a specified System Condition in which the Transmission Provider can curtail the reservation prior to curtailing other Long-Term Firm service. Conditional Firm service is charged at the same tariff rate as Long-Term Firm service. *See* BPA Conditional Firm Business Practice Version 23 available at https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/Contitional-Firm-Transmission-BP-V23.pdf.
[4] CFB will convert to LTF service if the facilities identified in the customers CF Service Agreement or their equivalents are completed or if LTF service otherwise becomes available. *See* BPA Conditional Firm Business Practice Version 23.
[5] CFR only applies to Conditional Firm Service which is not based on a bridge (e.g. no build has been identified and approved). CFR may transition to CFB if an upgrade has been identified and approved or it may convert to LTF if the appropriate requests are in queue. BPA may perform a Reassessment of the Customer's Number of Hours or System Conditions no more often than once every two years. *See* BPA Conditional Firm Business Practice Version 23.
[6] Output is defined as the maximum deliverable quantity, expressed in MWs, that can be generated or delivered over one hour. Output may be limited by a bidder's interconnection agreement, facility design, transmission rights, or contractual provisions.

Section 4 below presents the details, specifically the minimum thresholds and bid requirements, of how this provisional program would apply in the 2020 Renewable RFP.

The objective of the program is to provide an interim solution and allow for learning in a controlled manner, as the application of the key elements will have impacts decades beyond the provisional period. By applying the program to renewable RFPs executed during a limited window, PGE will have the opportunity to evaluate costs and risks associated with the approach and apply learning to future procurement activities.

3.1 Process Changes

An essential part of a comprehensive approach is assessing existing processes across the Company and determining appropriate modifications to align with the key elements of the program. PGE applied this approach during development of the provisional program to identify impacts to the various areas of PGE's business, both internal and external facing. Broadly, the Company categorized potential process changes to address risk and cost into two categories: RFP processes and business processes.

3.1.1 RFP Processes

Modifying PGE's transmission requirements, even under a provisional framework, introduces additional cost and risk to customers and PGE. In order to assess the impacts of these risks and attempt to appropriately mitigate them, PGE intends to make changes to certain elements of the RFP structure, specifically the scoring methodology and contract requirements.

Regarding the scoring methodology, PGE would adjust its capacity contribution/valuation methodology to account for any increased risk of delivery failure. Depending on the specific transmission plan of the bid, PGE would adjust the RECAP model to reflect the impacts of curtailment and long-term transmission for less than the full output, as reflected in the terms of the transmission service and coincident with the appropriate hours, on the capacity contribution of the resource. The impacts of this adjustment depend on the type of resource, its output profile, and its transmission plan, but will generally reflect the higher likelihood of curtailment and reduced delivery certainty associated with using conditional firm or long-term transmission for less than full output. Additionally, PGE would make changes to the non-price scoring methodology to assign points to non-quantifiable aspects, such as the difference in long-term availability between CFB and CFR service. CFR service inherently introduces more risk than CFB because it is not associated with a system upgrade and the reassessment terms and conditions create more uncertainty surrounding the changes to curtailment terms and its continued offering by the transmission provider.

Because the proposed transmission requirements introduce new risks for project deliverability, the RFP will reflect modifications to contract requirements to ensure these risks are addressed. The Company recognizes that certain events, curtailment or otherwise, may be outside the control of the parties and a contract must be flexible enough to address such events. However, changes to the transmission requirements result in a shifting of the risk allocation. PGE expects to address the increased deliverability risk by more clearly assigning deliverability responsibility to the supplier through more robust contract terms. Generally, these terms would address the quality of transmission procured for output above the level supported by long-term transmission, changes to the terms and conditions of the conditional firm service, minimum production guarantees, and failure to perform provisions should short-term transmission products not be available or the Bonneville Power Administration (BPA) cease to offer conditional firm service.

Historically, the Company has allowed bidders to assign transmission rights to PGE, which shifts the costs and management burden associated with the transmission service to PGE. The risks associated with accepting assignment of transmission rights was managed by the quality of the transmission service previously required. However, the transmission products accepted under the provisional program carry additional risk and management burden. Specifically, monthly firming and periodic reassessment of conditional firm service and the need to actively manage transmission service for up to 20% of the resource output.[7] Under procurement associated with the provisional program, PGE would not accept an assignment by default proposal from bidders. PGE would include contractual provisions that require commercially reasonable efforts to convert conditional firm service to LTF service when possible.
The Company would not explicitly require that conditional firm service be converted to LTF service regardless of cost. However, PGE would seek to ensure any existing conditional firm service is included in future BPA TSR Study and Expansion Processes (TSEP)[8] or future system expansion efforts in order to identify the costs of converting service.

3.1.2 Business Processes

PGE expects that changes would be required to existing business processes after the completion of an RFP. Many of these changes would be dependent on the composition of selected resource(s), specifically the transmission service and delivery plans. While PGE would endeavor to appropriately identify and evaluate costs and risks within an RFP process, it is possible that these costs or risks may manifest differently over time. The program framework would allow the Company to better track these changes and adjust its business processes to better accommodate changing operational paradigms, some of which are discussed below in Section 3.3.

At this point, readily identifiable impacts to existing business processes could include the purchase of short-term transmission service, carrying additional reserves, adjustments to next year output forecasts to account for expected curtailment or delivery amounts, and impacts to net purchases and sales of transmission and power. Notwithstanding the above RFP process efforts, it may be necessary and reasonable to reflect residual financial risks associated with renewable curtailment in PGE's power cost forecasting dockets and/or consider changes to the regulatory policy for sharing variations in power costs. PGE would provide specific proposals during later regulatory processes as the details of such proposals depend heavily on the details of the resulting resource(s) and associated contract(s) from an RFP, the current effective or expected operational paradigm, regulatory mechanisms, regional policies, and experience gained during the provisional program.

3.2 Monitoring and Reporting

The key results of any provisional program are learning and experience. PGE would aim to implement or modify the necessary systems and business processes to appropriately identify and track the impacts of the program. By designing and implementing new processes, PGE can more effectively learn from the provisional program and make necessary adjustments or refinements to increase effectiveness while actively managing associated risks.

[7] *See* BPA's Conditional Firm Business Practice, Section J.2.
[8] TSEP is the process by which BPA studies and evaluates requests for long-term transmission service.

These impacts cannot be fully known ahead of implementing the program and can vary from operational to financial. While some elements may be readily apparent, such as the amount of curtailment and the availability of long-term inventory, others are more difficult to identify at the outset, such as the impact to system operations in the form of additional reserves. Depending on the outcome of the resource procurement effort, PGE plans to initially monitor and report on the metrics in Table 1. Over time, these metrics may evolve, or indicators may be added or removed to ensure accurate results and useful reporting.

Table 1. Reporting metrics

Metric	Description
Conditional Firm Inventory	BPA publicly posts and regularly updates the amount of conditional firm inventory available for purchase. PGE would monitor these postings for changes over time.
Conditional Firm Usage	To the extent possible, PGE would monitor the usage of conditional firm inventory as a data point to determine if/how usage changes and if/how changes in usage impact existing users.
Conditional Firm Monthly Assessment Results	Ahead of each month, BPA can convert conditional firm service from NERC Priority Code 6-CF to 7-F depending on availability of short-term ATC. PGE would track the results of these "monthly firm up" actions when they occur.
Conditional Firm Curtailment	Conditional firm service has a NERC Priority Code of 6-CF and is curtailed prior to LTF, which has a NERC Priority Code of 7-F. PGE would track curtailment events that occur when Conditional Firm does not receive a "monthly firm up."
Impacts to Reserves	The proposed transmission requirements may result in the need to carry additional reserves, in the form of available generation, to handle events where output exceeds 80% or when there is a higher likelihood of a curtailment event.
Impacts to Operational Planning	In operations (e.g. next month, next day, etc.) PGE uses short-term forecasts to plan its system. These forecasts may adjust to reflect uncertainty regarding output or deliverability. PGE would seek to track these adjustments and determine their impacts to operational planning and costs.
Transmission Costs	Reducing the requirement for long-term transmission from 100% to 80% of output will increase the amount of short-term transmission products needed to ensure delivery during high-output periods. PGE does not yet know how these additional purchases will manifest as it depends on the final structure of the procured resource. Once the structure is known, PGE intends to track these additional costs.

PGE expects to report to the Commission and stakeholders via future IRP filings with a concluding report at the end of the provisional period. Future IRP filings after a resource has achieved COD will provide a reasonable cadence and venue to share the results and findings with interested parties. Ultimately, the results and findings from the program will inform PGE, stakeholders, the Commission, and regional partners as we collaboratively work toward a holistic solution to enable continued renewable development into the future.

3.3 External Policy Changes

The design and implementation of the program is based on current regional policies and operational paradigms, such as BPA's current product offerings and associated business practices detailing the implementation and use of these products. During the program period, these policies and paradigms may change, making future modifications necessary to conform to the then current practices. Such changes may be at the regional level, such as the expansion or evolution of the Energy Imbalance Market, or at the BPA level. The latter is more likely to have immediate impacts and present as changes in product offerings and terms, modified business practices or procedures, further enhancements and developments to TSEP. However, regional policy changes, such as a potential regional framework for resource adequacy or an expanded regional footprint for transmission planning, are likely to have broader and more uncertain impacts. In either case, the program framework and its implementation must remain sufficiently flexible to allow for necessary modifications to accommodate the uncertainty associated with changing paradigms. As part of its monitoring and reporting effort, the Company will seek to inform interested parties of changing dynamics and clearly identify modifications to the program or its implementation.

4 Conclusion

The Company looks forward to working collaboratively with parties in the 2019 IRP docket and a subsequent 2020 Renewable RFP docket to successfully implement the proposed provisional program. As indicated at the August 13, 2019 public meeting, PGE is open to holding an additional workshop ahead of the existing October 31, 2019 workshop to allow for PGE to present its proposal and answer clarifying questions. The Company will work with the parties to determine the level of interest and specific details.

Going forward, PGE continues to support a holistic solution that enables continued renewable development to benefit customers, while appropriately addressing potential risks to both customers and PGE. Such a solution will best allow PGE to balance reliable energy delivery and renewable development in order to continue to provide value to customers and achieve clean energy goals. The Company recognizes that pursuing such a solution will require significant effort and time on the part of PGE, the OPUC, stakeholders, and other regional entities. Efforts may start on a smaller scale, such as working with stakeholders to engage BPA on product improvements or product offering expansion, but collectively we should not lose sight of the desired end state.

5 2020 Renewable RFP Requirements

Eligible Transmission Service

The proposed 2020 Renewable RFP will allow for bidder participation for resources that have not received an offer for long-term firm transmission service. PGE will consider a range of specified transmission products as RFP eligible delivery strategies.

PGE will require that all resources have access to a specified quantity of long-term transmission from the project busbar to an accepted PGE point of delivery. Acceptable forms of long-term transmission include long-term firm, conditional firm bridge service, and conditional firm reassessment service (number of hours only – system condition service not accepted). Eligible long-term transmission products do not include non-firm, short-term firm, or unspecified transmission portfolio solutions. Resources must have sufficient long-term transmission rights to meet 80% of the project's maximum output capacity.[9] For the balance of the project, bidders may rely on short-term firm transmission products, but PGE will not accept deliveries on non-firm transmission.

For bidders proposing use of conditional firm reassessment service, PGE will only accept conditional-firm reassessment service whose curtailment frequency is limited by Number of Hours rather than enabled under specified System Conditions.[10]

Demonstration of RFP Eligibility

Bidders must demonstrate an achievable plan to secure required firm transmission service by the resource's commercial operations date. Achievable transmission service plans include either: a notice of available long-term firm inventory, a precedent transmission service agreement (PTSA), existing transmission service reservations delivering to PGE, a request or offer of transmission service (either redirect or original) with consideration for conditional firm service[11], a plan of service identified in a completed transmission service study (cluster study or individual study), demonstrated participation in an ongoing transmission study (cluster study or individual study).

Requirements Prior to Final Short-list

In order to remain an eligible bidder on PGE's final short-list, bidders must have received an acceptable offer of required transmission service by December 31, 2020. Acceptable offers of transmission service include: a full offer of transmission service, an executable PTSA, offer of conditional firm transmission service, or a proposed plan of service identified from a transmission study for which the bidder has received completed preliminary engineering results and has signed an Environmental Review Agreement.

Price Scoring Impacts

Transmission service is expected to impact project performance and value to PGE's customers. These impacts are expected to be most notable in the provision of capacity necessary to meet PGE's peak capacity needs. For this reason, PGE's determination of capacity value will account for the transmission service included in the project offer.

PGE's capacity value estimation methodology will only credit capacity value for the portion of a resource served on long-term transmission (including LTF, CFB, CFR). Capacity value will not be assessed for the portion of the resource expected to be served on short-term firm. Furthermore, for those resources that plan to rely on conditional firm service, the expected output of the resource will be diminished by the number of hours of allowed curtailment identified in the transmission service offer or plan.[12] PGE's methodology will assume that the curtailment occurs in those hours in which PGE experiences the greatest capacity need as it is

[9] A project's AC or DC nameplate capacity may differ than the maximum output. Output is defined as the maximum deliverable quantity, expressed in MWs, that can be generated or delivered over one hour. Output may be limited by a bidder's interconnection agreement, facility design, transmission rights, or contractual provisions.
[10] *See* BPA Conditional Firm Business Practice Version 23*,* Section B.3.
[11] *See Id.*
[12] If a conditional firm offer does not identify the Number of Hours, PGE will use its experience and available supporting data to assess the Number of Hours for determining the price score.

reasonable to assume that the curtailment occurs during the periods of greatest system stress also experienced by PGE.

Non-Price Scoring Impacts

Transmission service is an important risk factor for PGE to consider in its non-price scoring assessment. Offers that propose relying on long-term transmission service to serve only a portion of resource output and offers that propose utilizing conditional firm service present long-term risks that cannot be accurately captured in PGE's price scoring assessment. Such transmission service arrangements may lead to a greater number of curtailment events should short-term transmission service availability be limited or should conditional firm service be reassessed or withdrawn. For this reason, PGE's non-price scoring assessment will assign higher non-price scores to those offers which have greater shares of long-term service and to those offers that rely on long-term firm service as opposed to conditional firm service.

CASE: UE 427
WITNESS: CURTIS DLOUHY

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OREGON

STAFF EXHIBIT 206

UM 2166 September 1, 2023, Memo from IE to Staff

Highly-Confidential
February 6, 2024

BATES WHITE
ECONOMIC CONSULTING

HIGHLY CONFIDENTIAL INFORMATION
SUBJECT TO MODIFIED PROTECTIVE ORDER NO. 22-025

MEMORANDUM

September 1, 2023

TO: Patrick Shaughnessy
Kim Herb
Oregon Public Utility Commission

FROM: Frank Mossburg
Bates White, LLC

SUBJECT: Answers to Staff Questions

The purpose of this memo is to provide the Independent Evaluator (IE)'s answers to follow up questions regarding the IE Report on Contract Negotiations for PGE's 2021 All Source RFP.

1. What are the transmission product and quality requirements specified in PGE's 2021 RFP as approved by the Commission and issued to the market?

Per the RFP, to qualify as a renewable resource, a Bidder must have an achievable plan for long-term transmission service for 80% of the interconnection limit of the facility. Short term firm services may be used for the remaining 20% of the facility's interconnection limit. Eligible long-term transmission services included long-term firm, long-term conditional firm bridge, or long-term conditional firm reassessment. Long-term rights must match the duration of the contract term or include rollover rights.[1]

Dispatchable resources – i.e. standalone battery energy storage (BESS) units – had to have long-term firm transmission for 100% of the facility's interconnection limit. In this memo we focus on the requirements and bidding for renewable resources.

[1] RFP p 16.

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SUBJECT TO MODIFIED PROTECTIVE ORDER NO. 22-025

2. **Where in the RFP documentation was the option of submitting an alternative transmission plan included? Were there any specific criteria required of alternative transmission plans?**

In several public Q&A responses PGE noted that it will "consider alternative transmission plans provided bidders that provide a clear and executable path to procuring transmission service." There were no specific criteria stated for these plans.

3. **Did the bid submitted for Clearwater, one of PGE's benchmark projects, provide a viable alternative transmission plan to meet the transmission product and quality requirements specified in the RFP?**
   a. Has the project fulfilled this plan?
   b. What elements made the plan "viable"?

Clearwater's plan involves several steps. Recall that the offer was for 300 MW, split between a 100 MW PPA and a 200 MW BTA.

- All 300 MW are first delivered via a gen-tie line to Colstrip
- The supply would then be transmitted from Colstrip to Garrison via 300 MW of long-term firm service on the Northwestern transmission system held by NextEra. This service included rollover rights.
- To deliver supply from Garrison to PGE through the end of 2025 the project would use the following resources
  - 180 MW of long-term firm transmission with rollover rights held by NextEra
  - 50 MW of firm transmission via the redirect of an existing request with the Snohomish PUD held by NextEra. This service continues through 2025 but does not have rollover rights.
- For the remaining supply there were three options suggested by the bidder
  - Make short-term firm transmission purchases with BPA
  - Use PGE CTS rights when available

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SUBJECT TO MODIFIED PROTECTIVE ORDER NO. 22-025

- Purchase a leg of transmission via the Avista system to Mid-C and import via PGE's existing rights at Mid-C

After 2025 the Snohomish contract expires the project still has 180 MW of firm service and the same options for filling the gap. The additional time also allows for consideration of other options including filling the need with a new transmission service request with BPA.

The plan is viable due to the fact that the majority of firm transmission service is covered under a long-term firm agreement with rollover rights. In the short term the bid covers 77% of its output, just 3% short of the RFP requirement and there are other avenues for securing the remaining service. In the long term the bid covers 60% of its supply at the moment but there is additional time to secure more firm service to provide additional coverage. Note that PGE evaluators did not make any official decision regarding which option the bid would use going forward to fill additional transmission needs.

We believe that Clearwater's plan was sufficient and the project has, to the best of our knowledge, fulfilled this plan.

4. How many other projects submitted alternative transmission plans? Which ones and at what stage of the evaluation process?
a. Of these projects, how many were withdrawn or deemed nonconforming?
b. Of these projects, how many submitted a plan similar to Clearwater?

Several bidders submitted offers that did not meet the transmission requirements. Most all were deemed non-conforming though some were evaluated in part. One bid had an offer similar to Clearwater's but withdrew a portion of its offer. See the response to question #6 for more details.

5. If a project did not have the necessary transmission product and quality, what options were available to the bidder cure this deficiency?

Options included resizing the offer to meet the RFP requirements or, if multiple resources were involved, offering the resources as mutually exclusive.

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SUBJECT TO MODIFIED PROTECTIVE ORDER NO. 22-025**

6. How many bidders submitted bids for projects that did not conform to the transmission requirements? Of those, how many bidders were asked to reduce the size of projects to conform with the transmission requirements? In an Excel spreadsheet, please list those bidders and their projects, noting:

a. **Project Size**
b. **Project Bid Cost**
c. **The percent of the project's interconnection limit covered by a conforming transmission product**
d. **Whether the bidder included an alternative transmission plan**
e. **Whether the bidder ultimately withdrew their bid**
f. **Whether the bid made it to the initial shortlist or the final shortlist**
g. If they made it to the final shortlist, why the project was not selected.

See the attached Excel sheet. The following projects did not meet the transmission requirements of the RFP.

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[redacted]

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SUBJECT TO MODIFIED PROTECTIVE ORDER NO. 22-025

[redacted]

[redacted]

[redacted]

[redacted]

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SUBJECT TO MODIFIED PROTECTIVE ORDER NO. 22-025

[redacted]

[redacted]

[END HIGHLY CONFIDENTIAL]

As can be seen, the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** offer was the most similar to Clearwater, with **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** though it did not have the near-term coverage that Clearwater offered. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[2] See RFP p 17, "Bidders relying on BPA for transmission service are required to have either previously been granted eligible transmission service or have an eligible and active OASIS status Transmission Service Request (TSR) participating in the BPA TSR Study and Expansion Process (TSEP)".

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[redacted] **[END HIGHLY CONFIDENTIAL]**

For reference, the Clearwater PPA was priced initially **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Per PGE analysis (and confirmed by us) the project had a nominal levelized cost of **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** By virtue of its location and strong output Clearwater delivered more benefit via its capacity contribution than other bids so it's levelized benefits were about **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

Looking at these numbers the inclusion of the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** would likely have improved the offer, but it would not have been more competitive than the Clearwater offer.

[BEGIN HIGHLY CONFIDENTIAL] [redacted] **[END HIGHLY CONFIDENTIAL]** was the next closest offer to Clearwater, with **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[redacted]

[3] The BTA portion was estimated to be slightly more expensive, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** per our estimates.

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[redacted] **[END HIGHLY CONFIDENTIAL]** but there is no reason to believe it would have been more competitive than the Clearwater offer.

Note also that these offers are the initial offers into the RFP. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

No other offers were otherwise close to these in terms of transmission coverage, almost all others had zero firm coverage.

7. Did PGE instruct the Clearwater project to reduce the size of the project to meet transmission requirements? If not, do you know why?

a. **If the Clearwater project had been reduced in size to conform to its long-term firm transmission, would its relative price score have changed compared to other projects on the shortlist?**

The Clearwater project was not instructed to reduce its size to become confirming. We do not know why, though our best guess is that the evaluators believed the project was close enough in the short term (having 77% of its supply covered vs the RFP requirement of 80%) that the shortfall was not a major project risk.

If the project had been resized it likely would still have been a competitive project. PGE's main evaluation was based on levelized costs. The main cost for a wind project is the capital cost of the turbines and NextEra would have simply reduced their turbine order in response. There may have been some fixed costs that would be spread over a smaller MW base, but there is reason to think that any price movement upwards would likely have been small and the bid would have remined very competitive.

10. **How is the Clearwater transmission plan affected by the change in the closure date of Colstrip from 2025 to 2029?**

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There is no effect that we are aware of, as stated above, evaluators did not presume that a specific option was chosen to fill the remaining transmission needs of the facility and other options were presented.

11. What were the original costs for transmission associated with the Clearwater project in its bid into the 2021 RFP?

a. Are the costs of Clearwater's alternative transmission plans lower, higher, or the same as those included in its initial bid?

b. If the costs of Clearwater's alterative transmission plans are higher than those in its initial bid, by how much?

c. If the costs of Clearwater's alterative transmission plans are higher than those in its initial bid, would other projects have performed better relative to Clearwater in PGE's price scoring?

There were no differences between Clearwater's original and alternate costs. Costs for the plans outlined above **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

Importantly, the percentage covered by such transmission only mattered for qualification purposes - from an evaluation perspective PGE assumed that the entirety of Clearwater's output was delivered via firm transmission and paid for as well – there was no "free ride" for the additional supply.

12. The Final Report on Contract Negotiations noted that the Clearwater project's long-term transmission product offering "...does not quite meet the letter of the law from the RFP." Please explain whether this is different from not meeting the requirements of the RFP and describe why the IE believes it is reasonable to include the Clearwater project in this competitive bidding process.

This statement was just meant to indicate that the project did not meet the 80% long-term firm requirements in the RFP. We believed it was reasonable to include the offer in the process because it still represented a viable, cost-effective

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offer for supply that helped PGE meet its reliability and clean energy goals without pushing extensive risks onto the ratepayer.

This RFP took place amid severe industry upheaval, including price increases and extensive project delays and strain on supply chains. Most bids would not have met the COD requirements in the RFP **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** despite the RFP's prohibition against that practice. Evaluators had to be flexible in order to achieve the desired result. This is a common practice here and in similar RFPs across the country.

While it is certainly possible to run an RFP strictly per the letter of the document we do think it's important to keep the final goal of securing cost-effective supply for ratepayers in mind. An RFP run strictly to the letter that results in no purchases is typically not the desired outcome.

13. **Did the Clearwater project receive the same treatment as other projects without firm transmission?**

The only project in a similar space to Clearwater was the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**, though that did not have the near-term coverage that Clearwater offered. In retrospect we as the IE could have pushed harder **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** inclusion as offered in order to assure it had the same treatment as Clearwater. At the time we (and, we believe PGE evaluators) were more focused on making the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** offer the most competitive it could be. We saw that **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** was not competitive at all (a fact subsequently borne out by PGE analysis and verified by us) and thought that the more competitive **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** might stand a better chance as a standalone offer. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** did not consider this and simply withdrew without any discussion.

14. Does the IE's conclusion in its final report that proceeding with Clearwater is "reasonable" given PGE's renewable and capacity needs apply equally to other bids? If not, why not?

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Yes, for several reasons. First, of all renewable projects that did not meet the strict RFP requirements for transmission the Clearwater offer had the strongest "alternative" plan. It covers 77% of the supply in the short term, just 3% sort of the RFP requirement, and 60% beyond that. The short-term coverage buys the project more time to seek additional coverage - something no other bid offered - and there are multiple possibilities to fill the remaining need.

Second, and vitally important, the Clearwater offer was ultimately the best performing offer in PGE's evaluation. In the initial shortlist phase it had a cost/benefit ratio of **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

After the final shortlist process and contracting, during which **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** adjusted their pricing, the Clearwater project was even more competitive. See the table below which shows the cost and benefits of each bid as of January 2023, this is after **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** offered updated prices.

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[END HIGHLY CONFIDENTIAL]

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Recall that this assumes that all Clearwater supply is delivered at prevailing transmission rates, not just 60% or 77% of the supply. Per this analysis Clearwater is a net beneficial project, with costs being about 95% of benefits.

If Clearwater was not selected the next best bid was **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** project. This score above was prior to **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** stating that their price would increase about **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** – per our quick analysis this would be about **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** The project would also be delayed through **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

The next best offer was also **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Again, this score is prior to a March re-price from the bidder, which would have made the project less competitive. The project also was tied up in **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** which brought into question its viability. As of March, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

After that, the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** projects would likely be considered, but -at best – they would have a cost to benefit ratio of about **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** so the more likely outcome was a cost/benefit ratio somewhere in the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

After that were smaller projects **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** but these were not contacted and, given the industry trends at the time, would likely have had to raise their offers even more to make final contracts. All this points to alternative offers being much more costly than Clearwater.

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Third, the offer has its risks managed via two agreements with a respected third party developer. One of these is a pay for performance PPA the other a BTA. Both are similar to those offered by third-party bidders and feature standard risk protections such as delay damages and performance guarantees.

Fourth, the Clearwater offer provides 300 MW, or something close to the RFP target of 150 MWa. Most of the offers above **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** would not have provided this much supply, leaving PGE to pick up more at a later date.

Fifth, the project will be online by the required COD in the RFP of December 2024. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** projects would be delayed, some by a significant amount.

In sum, the Clearwater project is a cost-effective project that meets with RFP timelines and fulfills a large amount of the RFP target with effective risk protections via standard contracts. Alternative offers would all be less beneficial and most would be some combination of later in COD and/or smaller in size.

ATTACHMENT ONE - BIDS WITH ALTERNATIVE TRANSMISSION PLANS

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[END HIGHLY CONFIDENTIAL]

CASE: UE 427
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 207

Highly Confidential Responses to Data Requests

February 6, 2024

This exhibit is filed electronically.

CASE: UE 427
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Redacted Opening Testimony

February 6, 2024

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

A. My name is Anna Kim. I am the Energy Costs Section Manager employed in the Rates, Safety and Utility Performance Program 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 qualifications statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review and summarize the impact of the Clearwater Wind project on power costs.

Q. Did you prepare any exhibits for this docket?

A. Yes. In addition to my witness qualification statement, I prepared Exhibit Staff/302, responses to Staff data requests that are referenced in my testimony.[1]

[1] While the Company filed Highly Confidential workpapers in association with these DRs, Staff is referencing the non-confidential written response to these data requests. Exhibit Staff/302 contains only the non-confidential portion.

ISSUE 1. POWER COSTS

Q. How will addition of the Clearwater Wind project impact net variable power costs?

A. In its initial filing, the Company anticipates that the inclusion of Clearwater Wind will result in a decrease of $74.9 million in net variable power costs (NVPC) for 2024. This forecasted NVPC assumes an online date of December 31, 2023, and includes Production Tax Credit (PTC) benefits.[2] The Company has since updated this value based on its November 15 MONET run to be a decrease in NVPC of $92.6 million, a difference of approximately $17.7 million in additional savings.[3]

Q. Are there impacts to ratepayers outside of power costs?

A. Yes. Once additional costs are factored in, the total impact on including power costs and other costs is a $28.3 million decrease in the 2024 revenue requirements based on the Company's December 8 filing.[4]

Q. Why are power costs going down?

A. In terms of annual NVPC, wind generation does not have fuel expenses and is relatively low cost compared to alternative resources that would be used. Additionally, the Company predicts that Clearwater Wind also provides a "diversity benefit". Because this resource is located in a geographically and

[2] PGE/100, Abel – Batzler / 2-3.
[3] See PGE's December 8, 2023 filing "RE: UE 427 PGE Clearwater Renewable Resource Automatic Adjustment Clause – Net Variable Power Cost Update" in UE 427, found at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAH&FileName=ue427hah325488054.pdf&DocketID=23909&numSequence=12
[4] PGE/100, Abel – Batzler / 2-4.

climatologically distinct location, it will help moderate the generation of wind from resources located on the Columbia River Gorge. The Company initially estimated that the diversity benefit will be $11.8 million.[5]

Q. How did the Company calculate the estimated impact on NVPC?

A. The Company estimated the impact on NVPC by running the UE 416 MONET model with and without Clearwater Wind included. The Company also included the aforementioned diversity benefits, as well as transmission constraints to the Clearwater Wind assumptions prior to entering the inputs into MONET.[6]

Q. What capacity factor did the Company assume and how was this calculated?

A. The Company estimates an annual net capacity factor of **[HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** for both Clearwater East and Clearwater II.[7] As described in the Company's response to Staff DR 8, the Company hired a third party who used meteorological data from the site and forecasted transmission availability.

Q. Does Staff agree with this calculation?

A. No. As discussed by Dr. Dlouhy in Staff/200, the methodology to calculate the net capacity factor was consistent with how it was modeled in the RFP, but only assumes that 77 percent of Clearwater's nameplate capacity is covered by long-term firm transmission. However, Staff notes that this net capacity factor does not reflect an assumption of 80 percent long-term transmission, which

[5] PGE/100, Abel – Batzler / 28-29.
[6] PGE/100, Abel – Batzler / 28-31.
[7] PGE Highly confidential workpaper response to Staff DR 10.

was a minimum requirement for a bid to even be considered in the RFP. When Staff applied this assumption to the inputs of the MONET model, the capacity factor changed to **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**.

Q. How does the Company propose to update the capacity factor in future power cost dockets?

A. The Company proposes to use actual wind generation data to forecast Clearwater's net capacity factor.[8] The current forecast capacity factor is the factor that would be used for all five years of the rolling average. After receiving a full year of actual wind data, year one of the five-year rolling average would reflect actual generation, while years two through five will use the original capacity factor estimate. The Company would update the rolling five-year average for wind capacity factors as part of its annual power cost update proceeding.

Q. Does Staff support this methodology to update capacity factor?

A. No. Staff does not agree with the Company's proposal to update Clearwater Wind capacity factors based on actual production without taking into account the bid characteristics submitted into the original RFP. As discussed in Staff/200, Staff is concerned with how the Company's handling of the initial RFP may have resulted in a different outcome and further that the Clearwater Wind projects as built will not deliver the resources and benefits as anticipated.

[8] PGE Response to Staff DR No. 32.

Q. How does Staff propose that Clearwater be modeled in future power cost dockets?

A. Staff recommends two different adjustments for Clearwater Wind modeling in future power cost dockets. First, Staff recommends that for the first five years, the capacity used in the AUT forecast should remain at the level proposed by Staff above, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**. This number reflects the capacity factor calculated by the Company and adjusted to reflect long-term capacity availability assumed in the RFP. Additionally, Staff recommends that the Company's NVPC for this filing be calculated assuming that PGE indeed had 80 percent of its nameplate capacity covered by long-term firm transmission, as was required in its RFP.

Second, Staff recommends a performance mechanism to be applied to the Power Cost Adjustment Mechanism (PCAM) true-up where a) the cost of the first 10 MW of short-term transmission rights used to deliver power from Clearwater to PGE's load at any given time be held out of the PCAM or any other cost recovery docket, and b) whenever Clearwater is unable to deliver generated power to PGE's load due to lack of available transmission, any marginal power costs incurred to cover this shortfall be excluded from the results of the PCAM, including any curtailment fees that PGE is responsible for, netted against any revenues that PGE earns from selling power from Clearwater to another balancing authority. Please see Staff/200 for further discussion of this performance-based recommendation.

Q. What is the effect on the forecasted NVPC of assuming that Clearwater has Staff's recommended capacity factor and had 80 percent long-term firm transmission?

A. Staff estimates that making these two changes reduces the estimated NVPC forecast by $1.338 million. Staff recommends that the Company's revenue requirement in this docket be reduced by this amount.

Q. How did Staff calculate this NVPC adjustment?

A. Staff calculated this adjustment by modifying the MONET run used to calculate the updated NVPC in the December 8 filing. Staff first replaced the Company's assumed capacity factor for Clearwater of **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** with the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** capacity factor calculated by Staff. Staff then assumed that PGE would have an additional 10 MW of firm point-to-point transmission from the Garrison Substation to PGE's load, which would bring PGE up to the 80 percent firm transmission level. For modeling purposes, this was done by incrementing the additional 10 MW to the size of either the 180 MW of transmission from Clearwater Resources or the 50 MW of transmission from Snohomish County[9]—adding the 10 MW to either of these two contracts results in the same final adjustment. Additional discussion on the transmission modeling can be found in Staff/200.

Q. Does this conclude your testimony?

[9] PGE/100, Abel – Batzler/18.

A. Yes.

CASE: UE 427
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

February 6, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Anna Kim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Energy Costs Section Manager Rates, Safety and Utility Performance Program
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Economics Portland State University, Portland, OR Master of Environmental Studies, The Evergreen State College, Olympia, WA Bachelor of Arts, Environmental Science, University of California, Berkeley, CA
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) since July 2018 in the Energy Resources and Planning Division. My responsibilities include providing advice on energy efficiency policy, pilot and program evaluation, and oversight of energy efficiency programs run through the Energy Trust of Oregon Prior to working for the Commission, I worked for Seattle City Light as a power resource planner developing integrated resource plans. I also worked for five years as an evaluation consultant which involved evaluating energy efficiency and demand response pilots and programs and market research.

CASE: UE 427
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 302

Exhibits in Support Of Opening Testimony

February 6, 2024

December 22, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 427
PGE Response to OPUC Data Request 008
Dated December 8, 2023

Request:

Please provide a narrative description of how Clearwater Wind generation estimates were calculated. Please include any workpapers that are used to create these estimates.

Response:

Clearwater generation estimates were calculated by Lloyd Reed Consulting using meteorological data (e.g., wind speed, temperature) from towers that were on-site for several years. This generation data was modified slightly to account for forecast transmission availability. A more detailed description of this methodology is provided within the document titled "#2024 Clearwater RAC," and folder labeled "Generation Forecast," both included as part of PGE's highly confidential work papers.

January 18, 2024

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 427
PGE Response to OPUC Data Request 032
Dated January 4, 2024

Request:

This is a follow-up to DR 011. Please provide a narrative description describing assumptions about outages and resource availability that the Company uses when modeling of Clearwater Wind. Please describe the types of outages considered and their impact, such as but not limited to maintenance outages, shutoffs due to excess wind, transmission limitations, equipment failures, etc. Specify where these potential outages or reductions in availability are accounted for and how, such as in capacity factors or other modeling steps. Include any workpapers with formulae intact or references to workpapers already submitted.

a. Are your assumptions for outages in 2024 different from future years? If so, please explain how and why.

Response:

The factors impacting Clearwater availability, and which comprise the net capacity factor included in MONET for Clearwater are provided in Confidential Attachment 032-A. Additionally, transmission limits are modeled as described in PGE Exhibit 100 and within the MFR work papers included with PGE's filing. In future years, consistent with PGE's other wind facilities, actual wind generation data will be used to forecast Clearwater's net capacity factor.[1] For example, using PGE's five-year moving average modeling, the current forecast capacity factor is the factor used for all five years of the rolling average. Upon receiving one full year of actual wind data, year one of the five-year rolling average will reflect actual generation, while years two through five will continue to reflect the capacity factor included in this proceeding. The following year will have years one and two consisting of actual generation, with years three through five continuing to be the capacity factor included in this proceeding. PGE updates the rolling five-year average for wind capacity factors as part of its annual power cost update proceeding.

Attachment 032-A contains protected information and is subject to General Protective Order No. 23-132.

[1] PGE forecasts wind facilities using a five-year moving average of actual wind generation.

CERTIFICATE OF SERVICE

UE 427

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 6th day of February, 2024 at Salem, Oregon

Kay Barnes

____

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (971) 375-5079

UE 427
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