THE INDEPENDENT EVALUATOR'S ASSESSMENT OF PORTLAND GENERAL ELECTRIC'S DRAFT 2023 ALL SOURCE REQUEST FOR PROPOSALS

Presented to:
OREGON PUBLIC UTILITY COMMISSION

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I. INTRODUCTION AND SUMMARY

A. Introduction

Bates White, LLC (Bates White) is pleased to present this report, which reviews the filed Draft 2023 All Source RFP (RFP or Draft RFP) from Portland General Electric (PGE). Bates White serves the Oregon Public Utility Commission (Commission) as the Independent Evaluator (IE) for this RFP.

By way of background, Bates White personnel have served as IEs for State Commissions across the country, overseeing procurements for conventional, renewable, storage, grid services and other resources. We have worked for Commissions in Washington, Oklahoma, Hawaii, Illinois, Ohio, Pennsylvania, New Jersey, Maryland, Delaware, and elsewhere. In Oregon we served as the IE for PGE's most recent RFP, the 2021 All Source Request for Proposals (2021 RFP) and we have served as the IE for multiple transactions from PacifiCorp.

The purpose of this report is to provide our review of the Draft RFP. This is report is in direct response to OAR 860-089-0450.(3). which states that

> *"The IE must consult with the electric company on preparation of the draft RFP and submit its assessment of the final draft RFP to the Commission when the company files the final draft for approval."*

In addition, this report serves to fulfill the directives of Commission Order 23-146. In that Order the Commission adopted a Staff request, which read,

> *"Staff requests the IE, Bates White, prepare a report on PGE's last procurement in Docket No. UM 2166 and make recommendations to improve the 2023 AS RFP based on the findings presented."*[1]

We therefore begin with observations from the 2021 RFP and then analyze the Draft RFP. For ease of review, we structure our review of the latter around the Oregon Competitive Bidding Guidelines. In our review we looked at and beyond these Guidelines to make sure that we believed the RFP was open, fair, and transparent and would likely result in a successful procurement.

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[1] Order No. 23-146, Docket UM 2274, Appendix A, p 12, April 21, 2023.

B. Summary

While ultimately successful in filling the Company's needs the 2021 RFP had some issues regarding timelines for bid evaluation and project timing. In addition, there was much debate regarding contract terms in the design process. While this did not affect the ultimate bid evaluation and selection the response from bidders did suggest that PGE's term sheets featured several terms not consistent with what the competitive market will provide. For this RFP PGE has removed the term sheets and non-price scoring from the evaluation process, relying on parties to have good faith negotiations. We would urge PGE to incorporate the feedback it received into forthcoming negotiations and will monitor to ensure that terms are appropriate.

The Draft RFP is generally consistent with the Oregon Competitive Bidding Guidelines. However, there are a few areas that can be adjusted to potentially improve the process.

- The RFP features a tight timeline for new resources, requiring bids to come online (with some exceptions) by the end of 2025. While we understand that is when PGE could potentially need capacity we believe it would be beneficial to allow bids to come on line as late as the end of 2026. This would allow for more bids to participate and also give some cushion for later-stage projects that may encounter delays.
- Given the expanded timeline above as well as the documented delays in moving through transmission queues nationwide PGE should remove the requirement for a facilities study at final shortlisting so long as the bidder can reasonably prove that their project will meet the required COD.
- The 2021 RFP saw delays in the evaluation owing to several factors. While PGE did add extra time to the RFP schedule for this process we believe that additional time will help ensure the process runs as scheduled and minimize the chance of errata filings.
- As of now we have seen no evidence that S&P's treatment of imputed debt has changed from past practice or that such debt from Power Purchase Agreements (PPAs) is causing actual cost impacts for PGE customers. PGE should provide evidence of this or, consistent with past practice, remove consideration of imputed debt costs from the main evaluation.
- The Commission may wish to limit benchmark proposals to the targeted needs of the RFP (plus a small margin) in order to minimize pre-RFP competition for benchmark projects.
- Beyond these more substantive findings edits should be made to the RFP to regarding the NOI process and to provide; a) current capacity acquisition targets, b) clarification regarding credit requirements, c) more guidance as to how resources can participate if they wish to use existing PGE transmission services and d) draft renewable PPA and storage form agreements.

The rest of this report covers our work from lesson learned to the filing of the Draft RFP and presents our detailed review of the filing.

II. WAIVER FILING

Per OAR 860-089-0250.(2).(a) "Unless the electric company intends to use an RFP whose design, scoring methodology, and associated modeling process were included as part of the Commission-acknowledged IRP, the electric company must, prior to preparing a draft RFP, develop and file for approval in the electric company's IE selection docket, a proposal for scoring and any associated modeling." This requirement was granted a partial waiver in Order 23-146. As discussed more herein PGE is still in the process of developing its 2023 IRP. PGE expected to have large resource deficits in the future and had concerns that waiting for the formal IRP acknowledgement would hamper their abilities to procure supply to fill those deficits.

As part of this waiver request PGE requested to continue to employ Bates White as the IE for the 2023 RFP rather than hold another procurement process for an IE. This was also approved, although Bates White was requested to provide "lessons learned" from the 2021 RFP in order to improve the 2023 RFP.

III. LESSONS LEARNED FROM 2021 RFP

In this section we provide key findings from our work in the 2021 RFP. We attempt to draw out lessons for future RFPs where possible.

A. Evaluation Timelines

One issue that became apparent during the 2021 RFP process was that the timeline for bid receipt and evaluation laid out by PGE was more aggressive than what could actually be accomplished by the PGE evaluation team and the IE. At RFP issuance, the timeline was as follows.

- December 6, 2021 - PGE issues Final RFP.
- December 10, 2021 - Post-issuance bidder conference.

- January 4, 2021 – Benchmark bid due.
- January 17, 2022 — RFP proposals from Bidders due.
- February 11, 2022 - Initial short list identified.
- February 18, 2022 – Best and final price update.
- April 5, 2022 — PGE submits request for acknowledgment of short list to OPUC.
- June 2022 – Final contracts executed with winning Bidders as applicable.

To be clear the steps from February 11th onward were listed as subject to change depending on the quantity and complexity of bids received in response to the RFP.

While the RFP was issued on time the evaluation team ran into issues from the start. Most notably, the evaluation for the company-sponsored benchmark bids took far longer than scheduled. Per Oregon guidelines the benchmark bids are to be evaluated prior to the opening of third party bids. The original schedule allowed for about two weeks to review and score the benchmark offers.

The benchmark bids were received at the scheduled time. While the evaluation team did its best the evaluation took longer than planned, mainly due to the number of bids received and the amount of clarifying questions needed to properly evaluate the offers. The PGE evaluation team wrapped up their initial review around January 28th and sent the scoring to us for review. We sent our completed review of the scoring to the Commission on February 3rd. This meant that review of third-party bids, originally scheduled to start January 17th, did not start until about two and a half weeks later.

This had the effect of pushing back other dates. The initial shortlist, originally scheduled to be selected by February 11th, was selected on March 4th. The final shortlist was identified around April 27th. Ultimately the shortlist filing with the OPUC occurred on May 5th, about one month after the planned filing date.

While all parties worked as quickly as possible to stay on schedule we do feel that this had some effects on the bid review. Notably, while there were no errors that impacted the ultimate selection or ranking of bids, errata filings and analysis were needed due to several issues in the analysis. For example, on May 25 PGE filed to correct several issues in the analysis. This also required a revised IE report.

While the above delays were ultimately acceptable and the process was effective additional time in the schedule at the outset might have helped reduce errors and lead to a less rushed process. The takeaway here is to allow for a bit more leeway in RFP schedules, notably, the benchmark bid review time.

B. Contract Terms

Another finding from the 2021 RFP regards the general contract terms that bidders did and did not find acceptable. As background, PGE provided bidders term sheets outlining basic elements of any final contract that might be produced from a winning bid. Because bidders could be penalized on a non-price basis for deviations from these terms Stakeholders spent a great deal of time during the RFP design process arguing over what the proper value for certain items should be.

As the IE our general position was that, as long as the penalties were not too severe it was not a productive use of time to fight over commercial details when those details would eventually be subject to actual negotiations. In our experience contract terms can vary widely and, because contracts are the result of a push and pull between parties, sometimes one area that is more utility friendly will be offset by another area that is more bidder friendly. This means there is rarely a single "right" answer to the questions of, for example, what the terms and amounts of liquidated damages for COD delay should be.

Nonetheless, it is still instructive to see what bidders (including the benchmark team) thought of key terms in these term sheets. For that reason we went back and reviewed the bidder redlines to PGE's term sheets.

This is not meant to be a summary of all comments received, but rather to focus on some of the areas of most disagreement. We mainly focused on the redlines for Power Purchase Agreements (for renewables with and without Battery Energy Storage Systems (BESS) as well as standalone BESS systems). This was the most instructive set of comments as it comprised the most offers and had the largest number of requirements.

- Commercial Operation Date – PGE's term sheet asked for a guaranteed COD 120 days after the scheduled COD. Many bidders pushed out this date, typically to 180 days. Most bidders also requested extensions for delays due to force majeure, buyer caused delay, and delays caused by the interconnection provider.

- Delay damages - PGE's term sheet had a stepped delay damages function that moved from $100/MW per day up to $300/MW per day depending on the length of delay (these amounts were increased in the case of hybrid renewable and BESS facilities). Bidders generally accepted some form of stepped damage structure but usually adjusted the parameters to some degree (e.g. using the lowest level of damages for the first 60 days instead of the first 30). Some bidders also wanted a buy-down mechanism whereby damages could be paid in lieu of the facility meeting a specific capacity amount.

- Output guarantee – PGE's term sheet asked for bidders to guarantee 90% of the monthly expected facility output and allowed for termination if output was less than 50% of forecasted annual values for solar projects and 75% of annual output for wind projects in two of three years. The concept of monthly output guarantees was soundly rejected by bidders. Most bidders offered annual guarantees in the range of 80% of the expected output, though numbers did vary. Some bidders also adjusted the termination allowance.

- Mechanical availability – PGE's term sheet asked for a 97% availability from the facility. Bidders thought this was too aggressive, offering a range of alternatives from around 80% to 95%.

- BESS capacity guarantee – PGE requested that the bidder guarantee 90% of the proposed capacity be achieved during any test or pay 125% of the contract price per MW shortfall. This would also be a default if uncured in 30 days. Bidders responded with some downward movement in the penalty thresholds, particularly for defaulting.

- BESS Round trip efficiency (RTE)– PGE requested a guaranteed RTE of 90% in year one and it would be an event of default if this was uncured within 90 days. Bidders were fairly unanimous in opposing this, suggesting thresholds of between 80% to 87% with some offering schedules for annual degradation.

- BESS availability – PGE requested 98% monthly availability with a default if this target was missed in any two of twelve months. Bidders again did not agree to monthly accounting and offered annual availability guarantees anywhere from 85% to 97%. Bidders also pushed back on the termination clause, typically offering termination rights if this target was missed for two years or more.

- Test energy – PGE's term sheet offered no payments for test energy. Most bidders would not agree to this, wanting anywhere from 50% or more of the contract price for such energy.

- Excess energy costs – PGE's term sheet reduced payments for what it termed "excess energy". In their definition this was energy over 110% of the guaranteed monthly threshold. This would be paid the lesser of 75% of the contract price or 93% of a market index price. Most bidders were amenable to the concept, but offered some adjustments to those parameters.

- Curtailment – PGE proposed that sellers would not be paid (and would have no obligation to deliver) for curtailments as a result of system emergency, force majeure or transmission provider action and that PGE would also have the right to 400 hours of additional curtailment without pay. While there were some edits to the former concept the latter feature (additional curtailment hours) was soundly rejected.

- Performance Assurance– PGE requested $200/kW of generating capacity (plus, for hybrid proposals an additional $200/kW of storage capacity) pre COD and $100/kW after COD. The latter amount was subject to replenishment, meaning if a draw was made on the security the seller had the replenish the draw amount. Most bidders dropped these amounts to around $100/kW but terms did vary. Typically replenishment rights were struck or limited.

- Limits on damages. PGE limited liability to actual damages only. Some bidders asked to limit damages to the amount of performance security in the pre COD period.

There were fewer offers for Asset Purchase Agreements (APAs). Since these agreements did not cover the operating life of the facility they have fewer requirements than PPAs. Nonetheless we did observe similar edits for guaranteed CODs and delay damages as well as BESS performance requirements.

The 2023 Draft RFP does not feature term sheets. It does include draft pro forma agreements but these are for informational purposes only. There is no non-price score in the evaluation and no penalty for deviation from PGE's preferred terms. Therefore, there is no adjustment to the 2023 RFP that necessarily comes from this analysis. These findings, however, can help serve as a snapshot of what the market will offer and can help set a basis of expectation for contract negotiations resulting from this RFP. We hope that PGE will be receptive to this feedback in forthcoming negotiations and note that the IE will monitor these negotiations to ensure they are fair.

C. Size of benchmark offer

Another observation we had from the 2021 RFP was the size of the offer from the benchmark team. To put this in prospective some background might help, the 2018 Renewables RFP sought 100 average megawatts (MWa). The benchmark bid in that RFP provided about that much supply.

In the 2021 All Source RFP PGE was seeking about 375 MW of capacity and roughly 150 MWa of renewable resources. PGE was wiling to consider additional renewables procurements of another 65 MWa and was also looking for GEAR program supply.

PGE's benchmark submission was in excess of the stated targets for capacity and renewable energy. We understand and appreciate that PGE has a right to offer supply in its own RFP and we do approve of their process of partnering with established projects and developers to submit what is essentially the same as a third-party bid.[2] Moreover, benchmark partners are voluntary participants. However, we do have some concern that allowing unlimited offers from PGE may set a bad precedent for future RFPs. This may create what is essentially a shadow procurement where bidders attempt to partner with PGE and limit competition in the actual RFP. This may result in an unhealthy competitive dynamic.

Any actions to affect this dynamic should be taken with care as we do not wish to interfere too much with the competitive market. Nonetheless the Commission may wish to consider adding a cap to the amount of benchmark offer in a given RFP. This should be roughly equal to the stated need in the RFP, plus a bit of headroom (e.g. 10 percent) to account for the fact that project design sometimes necessitates a larger offer to maximize efficiency. We also note that the 2023 RFP has a fairly large need, so such a limit would likely have limited or no effect in this procurement.

D. Transmission Queue Processing

One element, that we addressed in our Final Report for the 2021 RFP, but that bears additional scrutiny here is the speed (or lack thereof) at which bids moved through the interconnection process. At the start we should say that this is not a problem exclusive to PGE. The massive increase in demand for clean resources, combined with the size and geographic spread of these projects has overwhelmed queues across the country.

These delays mean that limited numbers of bids could participate in the RFP. To some extent this is fine, there will always be projects that are not "fully baked" and need more time – projects that can participate in the next RFP process. The issue is that there are projects that, by most reasonable standards, should be able to participate are not able to.

[2] The traditional alternative would be for PGE to put together a less firm estimate of project costs based on EPC quotes.

In the final report we highlighted a set of projects that had been submitted into PGE's queue but had seen extensive delays in receiving a feasibility study. At the time PGE Transmission personnel stated that delays were caused by higher-queued projects dropping out.

Looking at the data published on OASIS (provided here as Attachment A) regarding study competition emphasizes how long it can take for bidders to make it through the queue. Since 2021 the average Feasibility study has taken 351 days, the average System Impact study 147 days and the average Facilities study 112 days.[3] To put this in prospective, the PGE OATT states that the transmission provider is to use reasonable efforts to complete the Feasibility study no later than 45 days after the provider receives the Feasibility study agreement.[4] Even considering that some of these delays may be bidder-caused, it still appears to take quite a while for bids to work through the process. This has the effect of limiting who can effectively complete in an RFP since bidders need to meet certain thresholds (e.g. having a completed System Impact study at bid submission) as well as the ultimate online date. PGE, to their credit, has tried to manage this and is attempting to move to a cluster study process to attempt to handle more requests.

The takeaway here is that, in managing RFP timelines around interconnection - specifically when bidders need to have studies completed and when projects must achieve COD – the RFP should have some flexibility. Bidders themselves noted this, as many asked for tolling of commercial operating dates forward in the case of interconnection-provider caused delay in their term sheet redlines.

E. Overall time frame for bid COD

Our final observation regards the overall tightness of the time frame from RFP issuance to requested commercial date. As background, the PGE 2018 Renewable RFP had bids due in mid 2018 with a scheduled approval in late 2018. In that RFP the preferred bid COD was December 2020 but bids could come on line as late as December 2021. So in total, there was about three and a half years between RFP bid submission and the latest a bid could come on line. For the 2021 RFP bids were due in early 2022 but had to come on line by the end of 2024. So, in this case there was less than three years between bid receipt and required COD.[5]

[3] See http://www.oasis.oati.com/pge/ "Performance Metrics" and "Interconnection Study Metrics (845)".

[4] PGE OATT Attachment O, Section 6.3. System Impact Studies have a rough target of 90 days and Facilities Studies range between 90 and 180 days.

[5] While no green tariff bids were selected, those projects did have additional time to come on line.

If we look at the process from the time bids were approved (i.e. final shortlist acknowledgement) there is a similar difference. The 2018 RFP had this in late 2018, giving bids about three years from final shortlist acknowledgment to the latest expected COD. In the 2021 RFP that acknowledgment was given in July of 2022 for a December 2024 COD. This gave bidders roughly two and half years from approval to COD.

Including time to negotiate contracts shows an even more tight timeline. The Wheatridge project was announced in early 2019, leaving almost three years between announcement and the last date the project could be on line per the RFP. The Clearwater facility was announced in October of 2022, leaving a bit over two years until the COD deadline. The Seaside and Troutdale projects were not announced until late April of this year, almost a year after the shortlist was submitted to the Commission.[6] While these were for BESS projects, which are a bit faster to build, this still left bids with a fairly tight time frame to reach COD. In fact, the Seaside project will not be on line until mid 2025.

The takeaway here is to make sure the entire RFP process, from bid submittal, through acknowledgement and contract negotiations to final COD leaves enough time for bidders to fully complete their projects.

IV. DETAILED DISCUSSION OF THE RFP

In this section we present our review of the Draft RFP. For ease of review we organize our comments in response to relevant sections of the Oregon Guidelines. We specifically address minimum RFP requirements, bid scoring and evaluation process, benchmark proposals and conclude with some additional suggestions which we feel could make the procurement more successful.

A. Minimum Bid Requirements

In this section we review the RFP against the relevant bid requirements as described in OAR 860-089-0250. The purpose is to make sure the RFP follows the basic requirements of the Oregon Guidelines.

[6] We should also note that outside events did cause some issues as well. The Department of Commerce solar tariff investigation began in Spring of 2022 and the Inflation Reduction Act was passed in August of 2022. The latter necessitated a price refresh from all parties on the shortlist.

"OAR 860-089-0250.(1) For each resource acquisition, the electric company must prepare a draft request for proposals for review and approval with the Commission, and provide copies of the draft to all parties to the IE selection docket. Prior to filing the draft RFP with the Commission, the electric company must consult with the IE in preparing the RFP and must conduct bidder and stakeholder workshops."

PGE filed the Draft RFP in Docket UM-2274 on May 19, 2023. Prior to filing PGE held a call with the IE to notify us of the general design of the RFP and point out some specific changes from the 2021 All Source RFP design. PGE also held stakeholder workshops. Specifically, PGE held a workshop on March 2, 2023 to provide a high-level overview of the Draft RFP process. PGE held a stakeholder and bidding workshop on May 26, 2023.

"OAR 860-089-0250.(2) The draft RFP must reflect any RFP elements, scoring methodology, and associated modeling described in the Commission-acknowledged IRP. The electric company's draft RFP must reference and adhere to the specific section of the IRP in which RFP design and scoring is described."

The evaluation process will utilize models and methodologies consistent with the 2023 IRP.[7] Specifically, PGE will use the Aurora model to simulate market prices and calculate energy values, the Sequoia model to assess the capacity value of bids and the Gridpath model to value the flexibility of bids.

For the final shortlist PGE will use the ROSE-E model to select portfolios and assess the cost and risk of each portfolio. PGE claims they will calculate the traditional scoring methods used in the 2023 IRP. The RFP specifically notes that a low market price sensitivity will be examined. Portfolio costs will be examined across "multiple economic futures."[8]

The key issue in this case is that the IRP has yet to be acknowledged by the Commission. While the models and methodologies proposed are similar to the most recently acknowledged IRP there could be changes to the process that will have to be incorporated into the analysis. We will coordinate with Staff during the evaluation process to ensure that this above directive is followed.

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[7] Draft RFP, Appendix N, p 8.

[8] Draft RFP, Appendix N, p 15.

"OAR 860-089-0250.(2).(b) In preparing its proposal, the electric company must consider resource diversity (e.g. with respect to technology, fuel type, resource size, and resource duration)."

The Draft RFP is reasonably open to qualifying resources given the preferences and restrictions embodied in Oregon law. The RFP seeks renewable and non-emitting resources over 10 MW (or 3 MW in the case of solar facilities) for a duration of between 15 and 30 years.[9] Most non-emitting technologies are accepted, as is pumped storage hydro. For pumped storage, PGE accommodates the long lead time of this resource by allowing such resources to be on line by no later than the end of 2028. PGE also will consider other long led time technologies that satisfy eligibility requirements, are commercially proven, and can be shown to require additional construction time.[10]

The Draft RFP does also allow for a variety of transaction types as it invites bidders to offer Power Purchase Agreements (PPAs) as well as ownership positions for renewable assets. Bidders may offer sales of existing assets and other structures.

The Draft RFP does indicate that scores for renewable resources will be determined separately from non-emitting dispatchable generation and that PGE may include other factors (transaction type, technology and location) in its shortlist determination.[11] This will help promote resource diversity.

In our Final Report on the 2021 RFP we made a suggestion for PGE to consider allowing bids from resources that would share existing transmission and interconnection capacity. The point of doing this was that transmission is a scare resource and this might allow for more complete utilization of these existing reservations; providing more renewable supply and potentially some additional capacity.

It is unclear if such bids can participate here. If they can, we would recommend that PGE make it clear that these types of bids are allowed in the RFP and explain how they can participate. This can include interconnection requirements, site control requirements, and permissible combinations. We do presume that any such bids would have secondary priority to existing resources, so this may limit, in some cases, the value of such offers.

OAR 860-089-0250.(3) At a minimum, the draft RFP must include: (a) Any minimum bidder requirements for credit and capability;

[9] Draft RFP p 11.

[10] Draft RFP p 10.

[11] Draft RFP p 13.

The Draft RFP does include requirements for credit and capability. Bidders must provide a reasonable plan to obtain project financing. Bidders must either support the fact that they are able to balance sheet finance the project or provide evidence of a good faith commitment by a lender prior to placement on the final shortlist.[12]

Going in to more detail, the Draft RFP states that "for investment grade Bidders, their long-term, senior unsecured debt must be rated BBB- of higher by Standard and Poor's, and Fitch, BBB (low) or higher by DBRS of Baa3 or higher by Moody's Investor Services, Inc. For non-investment grade Bidders, they must demonstrate, prior to the 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."[13]

PGE also provides what it terms as "Credit Guidance" (in the index) or "Credit Requirements" (on the section title page) in Appendix K of the Draft RFP. It is unclear if this is meant to be a requirement of subject to negotiations. Given that PGE is not soliciting redlines from bidders regarding standard form contracts and is planning to subject offers to good faith negotiations after the final shortlist approval we presume that these are indeed guidance and not requirements. The guidance suggests similar credit terms as PGE requested in its term sheets in the 2021 RFP.[14] As we noted above, most bidders offering PPAs proposed lower amounts and limits on replenishment. While PGE is free to ask for higher amounts we presume offers deviating from their guidance would be considered in good faith. We would suggest that PGE make this clear in the RFP.

> *"OAR 860-089-0250.(3) At a minimum, the draft RFP must include…(b) Standard form contracts to be used in acquisition of resources;"*

PGE does include standard form contracts. Specifically they include a form Renewable PPA, Storage Capacity Agreement, Asset Purchase Agreement and EPC Agreement. Per the Draft RFP bidders are not required to redline the form agreements and these are for reference purposes only.[15] All agreements are to be subject to good faith negotiations between bidders and PGE. One key agreement that is missing is a draft renewable and storage PPA. We would suggest that PGE provide such an agreement as well.

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[12] Draft RFP Appendix N, p 2.

[13] Draft RFP Appendix N, p 13-14.

[14] Amounts are $200/kW pre-COD and $100/kW post COD for PPAs and $100/kW for APAs.

[15] Draft RFP p 12.

As noted above, in the 2021 RFP much energy was devoted to discussions of commercial term sheets. In several areas bidders bid pushed back very strongly on what PGE requested, suggesting that PGE's requests were not truly reflective of what the market was willing to offer. At the moment we will presume that PGE will take this feedback under consideration when conducting its good faith negotiations. We also note that the IE will be monitoring negotiations as we did for the 2021 RFP to report on any deviations from this requirement.

"OAR 860-089-0250.(3) At a minimum, the draft RFP must include…(c) Bid evaluation and scoring criteria that are consistent with section (2) of this rule and with OAR 860-089-0400 (Bid Scoring and Evaluation by Electric Company)"

As we discuss above. PGE does include evaluation and scoring criteria. Because the bid scoring and evaluation criteria referenced in this section include a number of more detailed requirements we consider them individually later in this report.

"OAR 860-089-0250.(3) At a minimum, the draft RFP must include…(d) Language to allow bidders to negotiate mutually agreeable final contract terms that are different from the standard form contracts."

PGE does allow bidders to negotiate terms that are different from the standard form contracts. Specifically PGE states that definitive agreements between the bidder and PGE will be subject to good faith negotiations.[16]

"OAR 860-089-0250.(3) At a minimum, the draft RFP must include…(e) Description of how the electric company will share information about bid scores, including what information about the bid scores and bid ranking may be provided to bidders and when and how it will be provided;"

PGE does include this information. Per the Draft RFP at page 14 PGE will offer feedback to unsuccessful bidders on the competitiveness of their proposals. PGE commits to providing this after negotiations are complete with successful Bidders or the RFP is terminated. PGE will provide no confidential information but will disclose in which quartile the bid scored as well as identifying any minimum thresholds not met.

[16] Draft RFP, p 12.

Regarding the last item, as part of the RFP process we will work to ensure that any bidder that is facing disqualification will understand exactly why they are being disqualified and also have a chance to cure their shortfall. This is a standard procedure in most RFPs.

"OAR 860-089-0250.(3) At a minimum, the draft RFP must include…(f) Bid evaluation and scoring criteria for selection of the initial shortlist of bidders and for selection of the final shortlist of bidders consistent with the requirements of OAR 860-089-0400 (Bid Scoring and Evaluation by Electric Company)."

The Draft RFP does include bid evaluation and scoring criteria for selection of both the initial and final shortlist. We address compliance with OAR 860-089-0400 in a separate section.

"OAR 860-089-0250.(3) At a minimum, the draft RFP must include…(g) The alignment of the electric company's resource need addressed by the RFP with an identified need in an acknowledged IRP or subsequently identified need or change in circumstances with good cause shown;"

The RFP seeks to align with the 2023 IRP. This docket has not been acknowledged by the Commission. The RFP does point this out, specifically stating that the current acknowledgement date for the document is January 25, 2024.

While this is not an unprecedented event, issuing an RFP prior to acknowledgement does bring about some difficulties. These can come in two areas – both relating to items that can change in the IRP from the draft to the final acknowledged version. First, the targeted needs could change, either the capacity need or the renewables need. Second, the evaluation method and scoring metrics could change. Changes in the former are more easily delt with than changes in the latter as the latter might require re-running analysis. PGE and the IE will monitor the IRP process, with the assistance from Staff, and adjust the process here should any changes to these factors occur.

The Draft RFP does not fully identify the capacity target but does state that PGE expects to procure 181 MWa of renewable supply each year through 2030.[17] While the IRP capacity

[17] Draft RFP p 4.

need is not yet approved we do think it would be helpful to bidders if PGE also provided the current Reference case capacity need so as to indicate the potential size of the acquisition.[18]

"OAR 860-089-0250.(3) At a minimum, the draft RFP must include…(h) The impact of any applicable multi-state regulation on RFP development, including the requirements imposed by other states for the RFP process;"

Since PGE serves Oregon customers only this regulation is less relevant. We note that PGE is a member of the Northwest Power Pool and if developments out of the NWPP or similar entities affect the procurement we will work with PGE to adjust the process as necessary.

"OAR 860-089-0250.(4) An electric company may set a minimum resource size in the draft RFP, but it must allow qualifying facilities that exceed the eligibility cap for standard avoided cost pricing to participate as bidders."

The minimum resource size for the RFP is 3 MW for solar resources and 10 MW for other resources. This is the eligibility cap for PGE's Section 202 qualifying facilities. Per the above guideline there are no specific restrictions on qualifying facilities who exceed this size in bidding in this RFP.

B. Bid Scoring Requirements

In this section we focus on the bid scoring and evaluation requirements in the OAR Competitive Bidding Guidelines. We address relevant section by number below.

"OAR 860-089-0400.(1) To help ensure that the electric company engages in a transparent bid-scoring process using objective scoring criteria and metrics, the electric company must provide all proposed and final scoring criteria and metrics in the draft and final RFPs filed with the Commission."

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[18] Per the 2023 Draft IRP the company has a Reference case need of 506 MW in summer 2026 and 430 MW in Winter 2026. See Draft 2023 IRP p 136. https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp

PGE does describe its scoring process and does provide some guidance. Scoring is essentially based entirely on the price of the bid. Final shortlist selection will be based on the inclusion in the top performing portfolios and scored by the ROSE-E model.

> *"OAR 860-089-0400.(1).(2) The electric company must base the scoring of bids and selection of an initial shortlist on price and, as appropriate, non-price factors. Non-price factors must be converted to price factors where practicable. Unless otherwise directed by the Commission, the electric company must use the following approach to develop price and non-price scores:*
>
> > *(a) Price scores must be based on the prices submitted by bidders and calculated using units that are appropriate for the product sought and technologies anticipated to be employed in responsive bids using real-levelized or annuity methods. The IE may authorize adjustments to price scores on review of information submitted by bidders.*
> >
> > *(b) Non-price scores must, when practicable, primarily relate to resource characteristics identified in the electric company's most recent acknowledged IRP Action Plan or IRP Update and may be based on conformance to standard form contracts. Non-price scoring criteria must be objective and reasonably subject to self-scoring analysis by bidders.*
> >
> > *(c) Non-price score criteria that seek to identify minimum thresholds for a successful bid and that may readily be converted into minimum bidder requirements must be converted into minimum bidder requirements.*
> >
> > *(d) Scoring criteria may not be based on renewal or ownership options, except insofar as these options affect costs, revenues, benefits or prices. Any criteria based on renewal or ownership options must be explained in sufficient detail in the draft RFP to allow for public comment and Commission review of the justification for the proposed criteria.*

The Draft RFP satisfies these criteria, though there is a change from the 2021 RFP. This RFP no longer has a non-price score. Instead, all qualified bids will be evaluated solely on the basis of their price. Selected bidders will then engage in negotiations for a final contract with PGE.

This can help serve to eliminate many of the disagreements that we have seen in the past with RFP design. The one drawback to this system is that bidders may offer a price that is contingent on non-price terms that PGE does not accept. In such cases the bidder will likely have their bid rejected (though it is possible that the bidder might have a chance to re-price their offer with terms agreeable to PGE). To some extent this has always been an issue (2021 RFP bidders supplied term sheets and had to stand by their offers) so bidders will have to manage their own risk balance. Essentially a bidder will have to submit terms that can be adjusted within reason while still holding their bid price. Bidders may want to (and can) offer multiple variants of their bid with different contract terms.

We would suggest two areas of additional clarification in Appendix N to make the process more transparent. First, PGE should make it clear that bidders will have an opportunity to cure any failures to meet the minimum bidders requirements. The Draft RFP at present just states that "If a bid is found to be non-confirming, PGE will document why bids did not pass the minimum bidder requirements and will provide information to the bidder."[19] While PGE has typically afforded bidders a cure period and we assume they would here it would help to make that explicit. Second, PGE states it will take projects that meet minimum criteria and "perform well on price factors" to the initial shortlist.[20] We would recommend establishing a minimum quantity for selection to the shortlist. Typically this is between 1.5 and 2 times the expected need.

In addition, one new approach the PGE is proposing in this evaluation is a cost adder for Power Purchase Agreements to cover the cost of imputed debt. This is a somewhat controversial concept that has been around for quite a while. The concept of imputed debt gained prominence in a 2007 article from Standard and Poors. In that article S&P stated that they viewed PPAs as "fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity."[21]

To calculate this imputed debt S&P first calculates the net present value of a PPA's capacity payments using the company's average cost of debt as a discount factor. S&P then applies a "risk factor" to this NPV to reflect the risks in regulatory cost recovery. S&P notes that these risk factors typically range between 0% and 50% but can be as high as 100%. Risk factors are "inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements."[22] An additional step is needed if the contract is an "all-in" contract with a single price for energy and capacity (like many renewable PPAs). S&P uses a proxy capacity charge to estimate the implied capacity payment within a contract price.

So, for example, if a utility had a ten year PPA with a wind facility for an estimated cost of $1 million per year S&P would first estimate the portion of that cost that is for capacity. For

[19] Draft RFP, Appendix N, p 1.

[20] Draft RFP, Appendix N. p 13.

[21] Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements. May 7, 2007, p 1.

[22] Ibid p 2.

the sake of an example, assume 70%, leaving a payment of $700,000 per year. If we discount this using a cost of debt of 5% we get a total debt NPV of $5.4 million. Now, assume S&P assesses this to have a risk factor of 25%. They would then add an additional $1.35 million of hypothetical debt to the existing, actual debt on the utility's books.

Because of this potential to add debt, a utility will often add the cost of issuing additional equity to offset this debt, the theory being that additional imputed debt could hurt the utility's balance sheet and create a downgrade.

What makes imputed debt a controversial issue is the tenuous nature of the cost impact. As is clear from the above, there are at least two key assumptions that drive the calculation for a typical renewable PPA. The risk factor alone can (if assumed to be zero) entirely strike the cost. Because many utility PPAs go through a regulatory approval process (and many have clauses that cancel the contract if it is not approved for cost recovery) it is somewhat reasonable to assume that most will have a risk factor of zero. In addition, beyond the uncertain nature of the cost calculation it is unclear if the utility actually <u>will</u> issue additional equity to offset any implied debt.

The uncertain nature of these costs, combined with the fact that the analysis only adds costs to PPAs and therefore can push the selection of offers to utility ownership options have made the concept a controversial one. For this reason, in the past, in Oregon, consideration of imputed debt was pushed out of the initial evaluation and only allowed in the final shortlist selection.[23]

While we agree that debt imputation is a practice that S&P still engages in we are concerned that this is a theoretical cost that could serve to bias the selection of bids. Again, this policy has been public knowledge since 2007 and has not been considered in past Oregon RFPs to our knowledge. We have seen no additional evidence from S&P or other parties that this risk has increased in the past few years.

We are open to considering the possibility of assessing this cost, but first we would like to see evidence from PGE that S&P is becoming more aggressive in assessing these costs and that PGE has actually incurred increased costs as a result of debt imputation. This is in line with past requirements which allowed that the Commission may require the utility to obtain an advisory letter from a ratings agency to substantiate the utility's analysis.[24] Otherwise, we see no reason to depart from past precedent.

> *"OAR 860-089-0400.(5) Unless an alternative method is approved by the Commission under OAR 860-089-0250 (Design of Requests for Proposals)(2)(a), selection of the final shortlist of bids must be based on bid scores and the results of modeling the effect of*

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[23] Oregon PUC Order 14-149, Appendix A, p 3 "Consideration of ratings agency debt imputation should be reserved for the selection of the final bids from the initial shortlist of bids." (April 30, 2014).

[24] Ibid.

candidate resources on overall system costs and risks using modeling methods that are consistent with those used in the Commission-acknowledged IRP"

As discussed above, PGE will use IRP modeling tools and methods consistent with the 2023 IRP. PGE will look at various combinations of bids with the ROSE-E model. PGE will calculate the "traditional portfolio scoring metrics including cost, variability and severity as are described in Section 11.2 of the 2023 CEP/IRP."[25] Top portfolios will be scored 50% on expected costs and 50% on variability.

One additional item of note is that, upon selection to the final shortlist, there are additional requirements for site control, credit and interconnection. For the latter, bidders must also provide a facilities study. Given the delays noted above in transmission study queues we would suggest dropping this requirement so long as the bidder can still substantiate that their bid will make the RFP required COD. This would provide some room for delays in processing – and is more appropriate for projects that have a late 2026 COD (which we also recommend accepting below).

"OAR 860-089-0400.(5).(a) The electric company must use a qualified and independent third-party expert to review site-specific critical performance factors for wind and solar resources on the initial shortlist before modeling the effects of such resources.(b) In addition, the electric company must conduct, and consider the results in selecting a final short list, a sensitivity analysis of its bid rankings that demonstrates the degree to which the rankings are sensitive to:(A) Changes in non-price scores; and(B) Changes in assumptions used to compare bids or portfolios of bids, such as assumptions used to extend shorter bids for comparison with longer bids, or assumptions used to compare smaller bids or portfolios with larger ones."

The Draft RFP does make it clear (on page 5) that a third-party expert will provide a capacity factor verification report to be reviewed by the IE. Because no non price scores will be calculated there is no need to examine sensitivities for non-price scores.

As IE we will also receive the modeling results and we presume that PGE will also conduct any feasible sensitivity studies that we request. The goal of any such sensitivities will be to test the bid ranking and selection against key factors such as future price assumptions that will help illuminate the key risks and choices made in each resource selection. Should there be any issues with this approach we note that in our reports to the Commission.

[25] Draft RFP, Appendix N, p 15.

C. Benchmark Requirements

Per PGE the Company will offer "several" benchmark resources into the RFP. In this section we examine the RFP Design against the Guidelines regarding affiliate and self-build offers.

> *"860-089-0300.(1).b. Any individual who participates in the development of the RFP or the evaluation or scoring of bids on behalf of the electric company may not participate in the preparation of an electric company or affiliate bid and must be screened from that process."*

PGE does provide some guidance regarding separation of the benchmark team from the RFP team. Specifically on page 6 of the Draft PGE states that it will "[Designate] individuals with the appropriate levels of expertise and technical knowledge to RFP and bid development teams that do not interact on RFP related matters." This is a standard practice and we presume that PGE will provide a list of names to us specifying who is on which side of this divide.

On the same page PGE also states that individuals participating in the development of the RFP or the evaluation of bids were not involved with the preparation of a benchmark or affiliate bid and were screened from the process.

> *"860-089-0300.(2). An electric company may propose a benchmark bid in response to its RFP to provide a potential cost-based alternative for customers. The electric company may make elements of the benchmark resource owned or secured by the electric company (e.g., site, transmission rights, or fuel arrangements) available for use in third-party bids."*

Per Appendix P PGE intends to submit "several" benchmark resources into the RFP. In this Appendix PGE states that there is land in Northeast Oregon that is "under consideration" for use. We presume that PGE will update this if other assets are under consideration. PGE should also provide more detail regarding the resources as it becomes known to the RFP team.

As noted above, the last procurement featured a large amount of supply submitted by the benchmark team. We do recommend that the Commission at least consider a cap on benchmark supply equal to the RFP need plus a small margin for design factors though we understand and appreciate that such a policy might not be one that the Commission wishes to pursue.

“860-089-0350.(1) Prior to the opening of bidding on an approved RFP, the electric company must file with the Commission and submit to the IE, for review and comment, a detailed score for any benchmark resource with supporting cost information, any transmission arrangements, and all other information necessary to score the benchmark resource. The electric company must apply the same assumptions and bid scoring and evaluation criteria to the benchmark bid that are used to score other bids.“

PGE’s RFP contemplates the benchmark offers being submitted roughly three weeks prior to third party bids. Once those offers are submitted we will work with PGE evaluators to review and score the offers prior to the receipt of third party offers. This will include a review the unique risks posed by the benchmarks. As discussed above, benchmark evaluation took some time in the last RFP. Below we provide additional thoughts regarding the RFP schedule.

In addition, we do suggest one small language change. On page 8 of the RFP PGE states “PGE’s Benchmark bid must be submitted no later than 12:00 p.m. pacific time on September 15, 2023 and will be evaluated, scored and delivered to the IE prior to the receipt of third party bids.” We would suggest changing the last line to “prior to the <u>opening</u> of third party bids” as this is consistent with our practice and also allows for the possibility of evaluation delays.

D. Other Issues

Beyond the suggestions above we have three proposed edits that we believe would contribute to making the RFP a more successful procurement.

First, as discussed in detail above, the last RFP ran into difficulty in keeping to its schedule. To their credit PGE has added some days to each step in this RFP in recognition of this fact. Still, we believe that a bit more time in some of the steps would be helpful. For that reason we offer the schedule below. We presume that all steps up until benchmark bid receipt will be the same.

	PGE Timeline		Suggested Timeline	
Action	date	days	date	days
Benchmark Receipt	9/15/2023		9/15/2023	
RFP Bids due	10/6/2023	21	10/13/2023	28
Initial Shortlist	10/30/2023	24	11/10/2023	28
BAFO Update	11/17/2023	18	11/28/2023	18
PGE submits Acknowledgement Request	1/23/2024	67	2/2/2024	66

We start by adding another week to the evaluation time for the benchmark bids. This gives a similar timeframe for evaluation as was actually used in the last RFP. We also add a few more days to arrive at an initial shortlist as we were somewhat rushed to hit that deadline in the 2021 RFP.

We leave the time for creating the final shortlist unchanged. Here we acknowledge that PGE did provide a good deal more time that was used in the 2021 RFP. In that RFP we received BAFOs in mid-March and the acknowledgment was filed on May 5, a total of about 50 days. Here PGE has added roughly two extra weeks to that timeline, which we feel is appropriate.

Second one key requirement for bids is that they be online by the end of 2025. There are some exceptions – long lead time resources can come on by the end of 2028 and multi-phase projects can come online in part in 2025, with the second phase in 2026. This is driven by the capacity need in the IRP, which begins in 2026 in the Reference case.

While we understand the requirement, we noted above that bids struggled to hit the online targets in the previous RFP. Supply chain delays, interconnections delays and other shortages remain key problems for bids. Under the current schedule bidders would have only about two years from bid submission to COD, a very tight time frame, which could become even tighter if there is extensive time needed for contract negotiations. Furthermore, the 2026 need goes away if PGE is able to extend existing contracts.[26]

To give some breathing room to bidders and to expand the potential number of offers in this RFP we would suggest that the COD requirement be moved back to the end of 2026. For PGE's renewable targets this would be a limited risk since their actual requirements are for 2030. We do acknowledge that this opens up some risks for capacity supply but we note that this can be accounted for in the evaluation and that PGE may extend current contracts to cover the need. For reference, PacifiCorp's current RFP allows for bidder to come in as late as the end of 2027.

Finally, we observe that the Draft RFP asks for a notice of intent to bid. Specifically, on page 7 the RFP states that bidders who wish to bid <u>must</u> submit a notice of intent to bid by July 14, 2023. While we are fine with a NOI process, this is prior to the final RFP even being issued. We would recommend that this either be made optional, or moved until after the final RFP issuance, we suggest the beginning of September as a possible time.

[26] 2023 IRP, p 136.

Attachment A - PGE Processing Reports

Quarterly Interconnection Study Metrics

	2021	Q1	Q2	Q3	Q4
	FEASIBILITY STUDY (FS) Processing Time				
	OATT Attachment O 3.5.2.1,				
A	Number of Interconnection Requests that had FS completed	1	1	0	0
B	FS that were completed >45 days after agreement execution	1	1	0	0
C	FS in process and incomplete >45 days after agreement execution	1	0	9	11
D	Mean time (in days) from executed agreement to study completed	150	249	N/A	N/A
E	Percentage of Interconnection FS exceeding 45 days to complete	100%	100%	100%	100%
	SYSTEM IMPACT STUDY (SIS) Processing Time	**Q1**	**Q2**	**Q3**	**Q4**
	OATT Attachment O 3.5.2.2				
A	Number of Interconnection Requests that had SIS completed	0	1	1	0
B	SIS that were completed >90 days after agreement execution	0	0	1	0
C	SIS in process and incomplete >90 days after agreement execution	0	0	0	0
D	Mean time (in days) from executed agreement to study completed	N/A	70	105	N/A
E	Percentage of Interconnection SIS exceeding 90 days to complete	N/A	0%	100%	N/A
	Interconnection Facilities Studies (FaS) Processing Time	**Q1**	**Q2**	**Q3**	**Q4**
	OATT Attachment O 3.5.2.3				
A	Number of Interconnection Requests that had FaS completed	0	0	1	0
B	FaS that were completed >90/180 days after agreement execution	0	0	0	0
C	FaS in process >90/180 days after agreement execution	0	0	0	0
D	Mean time (in days) from executed agreement to study completed	N/A	N/A	80	N/A
E	Percentage of Interconnection FaS exceeding 90/180 days to complete	N/A	N/A	0%	N/A
	Interconnection Service	**Q1**	**Q2**	**Q3**	**Q4**
	OATT Attachment O 3.5.2.4				
A	Number of requests withdrawn during quarter	1	1	2	0
B	Number of requests withdrawn during quarter before completion of any study or study agreements executed	0	0	0	0
C	Number of requests withdrawn from queue during quarter before completion of a SIS	0	0	0	0
D	Number of requests withdrawn during the quarter before completion of a FaS	0	0	0	0
E	Number of requests withdrawn after execution of a LGIA or Customer requests filing an unexecuted LGIA	0	0	0	0
F	Mean time (in days) from valid request to request to withdraw	937	1466	456	N/A

Aggregate Study Hours for PGE Intercnnection Requests: 382.5 [Per Section 3.5.4 (ii) of Attacment O of PGE's OATT]

	Quarterly Interconnection Study Metrics				
	2022	**Q1**	**Q2**	**Q3**	**Q4**
	FEASIBILITY STUDY (FS) Processing Time				
	OATT Attachment O 3.5.2.1,				
A	Number of Interconnection Requests that had FS completed	3	0	2	2
B	FS that were completed >45 days after agreement execution	3	0	2	2
C	FS in process and incomplete >45 days after agreement execution	8	12	11	9
D	Mean time (in days) from executed agreement to study completed	265	0	377	490
E	Percentage of Interconnection FS exceeding 45 days to complete	100%	0%	100%	100%
	SYSTEM IMPACT STUDY (SIS) Processing Time	**Q1**	**Q2**	**Q3**	**Q4**
	OATT Attachment O 3.5.2.2				
A	Number of Interconnection Requests that had SIS completed	0	0	2	0
B	SIS that were completed >90 days after agreement execution	0	0	1	0
C	SIS in process and incomplete >90 days after agreement execution	0	1	0	0
D	Mean time (in days) from executed agreement to study completed	0	0	207	0
E	Percentage of Interconnection SIS exceeding 90 days to complete	0%	0%	100%	0%
	Interconnection Facilities Studies (FaS) Processing Time	**Q1**	**Q2**	**Q3**	**Q4**
	OATT Attachment O 3.5.2.3				
A	Number of Interconnection Requests that had FaS completed	1	0	0	0
B	FaS that were completed >90/180 days after agreement execution	1	0	0	0
C	FaS in process >90/180 days after agreement execution	0	0	0	0
D	Mean time (in days) from executed agreement to study completed	144	0	0	0
E	Percentage of Interconnection FaS exceeding 90/180 days to complete	100%	0%	0%	0%
	Interconnection Service	**Q1**	**Q2**	**Q3**	**Q4**
	OATT Attachment O 3.5.2.4				
A	Number of requests withdrawn during quarter	0	0	0	0
B	Number of requests withdrawn during quarter before completion of any study or study agreements executed	0	0	0	0
C	Number of requests withdrawn from queue during quarter before completion of a SIS	0	1	0	0
D	Number of requests withdrawn during the quarter before completion of a FaS	0	0	0	0
E	Number of requests withdrawn after execution of a LGIA or Customer requests filing an unexecuted LGIA	0	0	0	0
F	Mean time (in days) from valid request to request to withdraw	0	14	0	0

Aggregate Study Hours for PGE Interconnection Requests: 319 [Per Section 3.5.4 (ii) of Attacment O of PGE's OATT]

	Quarterly Interconnection Study Metrics				
	2023	**Q1**	**Q2**	**Q3**	**Q4**
	FEASIBILITY STUDY (FS) Processing Time				
	OATT Attachment O 3.5.2.1,				
A	Number of Interconnection Requests that had FS completed	1	0	0	0
B	FS that were completed >45 days after agreement execution	1	0	0	0
C	FS in process and incomplete >45 days after agreement execution	13	0	0	0
D	Mean time (in days) from executed agreement to study completed	582	0	0	0
E	Percentage of Interconnection FS exceeding 45 days to complete	100%	0%	0%	0%
	SYSTEM IMPACT STUDY (SIS) Processing Time	**Q1**	**Q2**	**Q3**	**Q4**
	OATT Attachment O 3.5.2.2				
A	Number of Interconnection Requests that had SIS completed	0	0	0	0
B	SIS that were completed >90 days after agreement execution	0	0	0	0
C	SIS in process and incomplete >90 days after agreement execution	4	0	0	0
D	Mean time (in days) from executed agreement to study completed	0	0	0	0
E	Percentage of Interconnection SIS exceeding 90 days to complete	100%	0%	0%	0%
	Interconnection Facilities Studies (FaS) Processing Time	**Q1**	**Q2**	**Q3**	**Q4**
	OATT Attachment O 3.5.2.3				
A	Number of Interconnection Requests that had FaS completed	0	0	0	0
B	FaS that were completed >90/180 days after agreement execution	0	0	0	0
C	FaS in process >90/180 days after agreement execution	2	0	0	0
D	Mean time (in days) from executed agreement to study completed	0	0	0	0
E	Percentage of Interconnection FaS exceeding 90/180 days to complete	100%	0%	0%	0%
	Interconnection Service	**Q1**	**Q2**	**Q3**	**Q4**
	OATT Attachment O 3.5.2.4				
A	Number of requests withdrawn during quarter	0	0	0	0
B	Number of requests withdrawn during quarter before completion of any study or study agreements executed	0	0	0	0
C	Number of requests withdrawn from queue during quarter before completion of a SIS	0	0	0	0
D	Number of requests withdrawn during the quarter before completion of a FaS	0	0	0	0
E	Number of requests withdrawn after execution of a LGIA or Customer requests filing an unexecuted LGIA	0	0	0	0
F	Mean time (in days) from valid request to request to withdraw	0	0	0	0

Aggregate Study Hours for PGE Interconnection Requests: 555.25 [Per Section 3.5.4 (ii) of Attacment O of PGE's OATT]