THE INDEPENDENT EVALUATOR'S SECOND 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 BACKGROUND

This is the second report of the Independent Evaluator regarding Portland General Electric (PGE)'s 2023 Draft All Source Request for Proposals (RFP). Bates White serves as the Independent Evaluator (IE) for the Oregon Public Service Commission (Commission). Bates White previously submitted an analysis of the draft RFP filed in Docket UM-2274.[1] The purpose of this second report is to address select issues raised in stakeholder comments and PGE reply comments.

Since the filing of our First RFP Report PGE has held a stakeholder session to review the draft RFP and answer questions from bidders. Stakeholder comments have been received from several parties; including the Northwest & Intermountain Power Producers Coalition (NIPPC), Renewable Northwest, Commission Staff, the developers of the Swan Lake and Goldendale projects, Bright Night Power, NewSun Energy and the Oregon Solar + Storage Industries Association (OSSIA) as well as the PGE Benchmark Team. PGE also filed reply comments, along with a redlined RFP which reflected edits proposed in response to comments.

Before discussing key remaining issues we do want to commend PGE for making several positive changes to the draft RFP in response to stakeholder comment and our First RFP Report. Such positive changes include; an extended COD date, adjusted schedules, less strict transmission requirements and more. This has helped limit the scope of remaining issues and move the process toward a successful conclusion.

II. KEY REMAINING ISSUES

In this section we discuss some issues that remain unsettled in the RFP design. This is not meant to be a comprehensive list of issues but rather issues we believe are more central to the success of the RFP.

[1] Independent Evaluators Assessment of PGE's Draft All Source RFP, Docket UM-2274, May 31, 2023. (First RFP Report).

A. Transmission Requirements

Stakeholders raised a number of issues regarding the transmission requirements in the RFP. One key issue raised was a request for PGE to accept Bonneville Power Association (BPA's) Conditional Firm – System Conditions product (System Conditions) as a conforming product in this RFP. This request was made by NIPPC and the PGE Benchmark Team.[2]

As a brief background, in evaluating long-term transmission service requests (TSRs) BPA looks at the system under a variety of conditions and then determines if service can be granted or if upgrades are needed. As part of this process bidders can request Conditional Firm Service (CFS), which means that they will receive Firm service with certain exceptions. Depending on the path requested BPA may offer two types of Conditional Firm Service; Number of Hours or System Conditions.[3] Under the former, BPA may curtail firm service up to a specified number of hours. Under the latter, service may be curtailed when certain conditions on the system are met (e.g. when real-time analysis identifies curtailment to mitigate transmission constraints on a specified path). PGE initially proposed to allow CFS-Number of Hours but did not allow CFS-System Conditions.

This is an issue because long-term firm service is very scarce and BPA is increasingly offering only System Conditions service. Particularly relevant for this RFP is that the Portland sub-grid area is becoming more congested. BPA has stated that they may add system conditions constraints on new paths to manage this congestion. At this point BPA does not have the ability to offer Number of Hours CFS in this area because paths in the area have not yet been identified, do not have path transfer capability numbers and do not have congestion frequency data. Therefore, BPA will only offer CFS to TSRs impacting the greater Portland area on a System Conditions basis.

At this point PGE does not want to adopt the System Conditions product because they "[do] not have guidance from BPA as to what the risk calculation should be in acquiring an RFP resource that will rely on System Conditions products for a 15-30 year period beginning in the mid 2020's.[4]" PGE proposes retaining the minimum requirement for a resource to have long term firm or CFS Number of Hours service. However, if there is insufficient volume to construct

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[2] Northwest and Intermountain Power Producers Coalition's Comments on Draft RFP, Docket UM-2274, June 16, 2023. (NIPPC Comments) p 3 and Portland General Electric Comments Regarding PGE's All Source RFP (UM 2274), Docket UM-2274, June 16, 2023 (PGE Benchmark Comments) p 2.

[3] These are further divided into two categories (Bridge or Reassessment) depending on if the customer will fund transmission expansion.

[4] Portland General Electric's Reply Comments, Docket UM-2274, June 28, 2023, (PGE Reply Comments) p 9.

a final shortlist PGE may elect to consider projects who are impacted by flowgates upon which they were not given the option of CFS Number of Hours.[5]

Before discussing this issue in depth, one initial issue is that this position is not clear in the RFP documents. If this is to be PGE's position, they should add a footnote to this effect in the description of transmission requirements.

Beyond this, we sympathize with the difficulty of valuing a bid with an unknown risk profile. However, we would suggest that if PGE has data regarding the specific system condition that a bid is subject to then they should be able to model that offer. While we agree that system conditions can change over a 15 or 30 year operating period this can be addressed by examining sensitivities - this can include either increasing the curtailment frequency by a set amount or a breakeven analysis looking at how much curtailment would need to be in order to not select the offer. While curtailment is uncertain this is also true about many variables in planning (gas prices, load, market prices, etc.) and these variables are able to be reflected in planning and bid selection.

We would therefore recommend that PGE at least as a threshold matter accept bids supported by CFS-System Conditions service provided that PGE has sufficient data to model the specified conditions. To be clear we only refer here to conditions that PGE has data for. If such data does not exist at this point then we agree that it would be reasonable to not accept such a product.

As a related matter, the PGE Benchmark Team requested that participation in BPA's 2023 Transmission System Expansion Process (TSEP) be deemed conforming even if completed studies and a final agreement are delayed by BPA.[6] PGE declined to make this change noting that in the most recent BPA report most required upgrades for delivery to PGE are estimated for completion in the 2030s, so new requests would likely be subject to similar results or worse. PGE did offer that 2023 TSEP projects that "believe they have a viable path to meeting CODs outlined in this RFP should provide a narrative and detail as to their specific situation."[7] PGE states that they may consider such projects that can show they are not likely subject to such long-term upgrades.

We agree with PGE in concept but think it might be worth spelling out how a bidder in such a situation would be treated and the risks that bidder may face. Per BPA testimony in May of this year the 2023 study was expected to be completed in November of 2023.[8] Under the

[5] Ibid p 10.

[6] PGE Benchmark Comments p 1.

[7] PGE Reply Comments, p 7.

[8] Testimony of John Hairston, Hearing on Examining the President's Fiscal Year 2024 Budget Proposal for the U.S. Bureau of Reclamation, U.S. Fish and Wildlife Service, National Oceanic and Atmospheric Administration and the Power Marketing Administrations, May 23, 2023, p 5.

current proposed RFP schedule the initial shortlist is to be targeted for November 10. Therefore, to our mind, to be a conforming offer, bidders in the 2023 TSEP would a) have to have their results prior to the shortlist date and b) have those results support the project COD as proposed. If a bidder is comfortable with these conditions then they would be free to submit offers, but they should be clear on the risks involved.

B. Online Dates

In the First RFP Report we raised the issue of the required online dates for bids. Specifically, the initial requested online date of December 31, 2025. We noted that while we understood that PGE was forecasting a 2026 capacity need, and therefore seeking resources to fit this need, we believed this requirement was likely too strict and should be moved out to allow for more bids to offer as well as to accommodate unexpected delays for projects that otherwise might be able to meet a 2025 deadline.[9]

Other stakeholders also pushed back on this requirement. In response, PGE has relaxed the online date requirement. Bids are now allowed to come online as late as December 31, 2027. However, PGE also says that projects that can meet the December 2025 online date will be "prioritized" to meet the capacity need (assuming such need is acknowledged in the IRP).[10]

While we can appreciate the concept, it is unclear to us what PGE means by "prioritized". The latest draft RFP simply repeats this language but does not make it clear how this prioritization will be carried out.

We believe PGE should provide additional details as to how this preference will be implemented. While we are open to various methods one possibility would be for all bids that can meet the 2026 capacity need to be automatically placed on the initial shortlist. This does of course, assume, as PGE does, that there is an acknowledged need for capacity in 2026 as a result of the IRP process. This would assure that near-term bids will at least be considered in the final shortlist selection.

The general concern with prioritizing near-term offers is that such resources could be more expensive than others and that ratepayers would pay a premium over a 15 to 30 year contract just to meet an single year's need. Therefore, PGE may, as part of its final shortlist process, test portfolios with a 2026 resource against others without such a resources and with a generic capacity fill. In its final selection PGE can then weigh the costs and benefits of acquiring

[9] First RFP Report, p 23.

[10] PGE Reply Comments, p 3.

a near-term resource that may be more expensive and make a reasonable selection as the data dictates.

C. Imputed Debt

In our first report we took issue with PGE's proposal to include an adder for Power Purchase Agreements to offset the cost of "imputed debt" calculated by ratings agencies such as S&P. We noted that such costs had long been excluded from Oregon RFP processes and that the nature of the cost impact was fairly theoretical. We did allow that such an adder might be justified if PGE could show specific examples of the imputation of debt on their balance sheet that threatened their credit rating.[11] Other stakeholders raised similar concerns in their comments.

PGE provided some response to this issue in their reply comments. PGE points to the 2007 S&P paper which outlines their imputed debt method as justification for the risk premium it uses.[12] However, absent a reference to the risk premium being used in S&P's "own evaluation of imputed debt for PGE", PGE declines to provide additional information as to how imputed debt affects the company balance sheet and the level of risk currently presented by this process. We are still lacking such information as a) the amount of imputed debt that S&P has already added to PGE's balance sheet, b) statements from S&P regarding indicators for PGE that may trigger a downgrade, and c) the potential effect of new PPAs in triggering these specific indicators. Without such concrete details it is impossible to tell if the addition of imputed debt is a real and substantial threat to PGE's balance sheet and the specific magnitude of that risk. Therefore, we continue to recommend that, consistent with prior practice, imputed debt not be considered as a factor in this RFP process.

D. Contract Redlines

As discussed in our First RFP Report, a change from past practice proposed in this RFP is that PGE will not offer a non-price score to bidders based on deviations from their standard form contracts. Instead, PGE will rely on commercial negotiations with selected parties after a final shortlist has been selected. In our report we generally approved of this method but noted that there could be difficulties if bidders priced their offer based on contract terms that were

[11] First RFP Report, p 19.

[12] PGE Reply Comments, p 15.

unacceptable to PGE.[13] We also noted that this was, in a sense, always a problem in RFPs without a fixed standard form contract and that bidders would have to be prepared to be flexible in commercial terms while holding their price.

Stakeholders were generally supportive of this move, however some recommended that redlines still be required to demonstrate the basis for the bid.[14] PGE in its reply comments declined to add any requirements to supply edits to form contracts.[15]

We think this approach is generally appropriate as it makes the scoring more transparent and saves parties the work of essentially conducting a commercial negotiation in the RFP design phase. However, we would add one suggestion. If a party is concerned that their required contract conditions for a given price will not be accepted they should submit contract redlines with their offer. If PGE finds such conditions completely unacceptable they should communicate this to the bidder and the bidder should then have an opportunity to adjust their offer. To be clear we are talking about terms that are truly not acceptable in form or concept to PGE – for example, an indexed pricing scheme – not terms that PGE would not prefer (e.g. a lower amount of pre-bid security). Again, this is something that was essentially done in the past – PGE has always had a right to respond to a bidder who proposed a major risk shift in the contract that would not be accepted.

III. OTHER MISCALLANEOUS ISSUES

In this section we review some issues that, while less important than those noted above, still, for one reason or another deserved some comment in this report.

Transferability discount

As part of their evaluation of offers that will be owned by the utility PGE is proposing to discount any tax credits received to account for some loss of value in selling such credits to a third party. This is an adjustment to past practice where the cost of a deferred tax asset was added to such bids to account for the fact that PGE could not use all or a portion of the tax credits immediately. This change was brought about by the passage of the Inflation Reduction Act which made it easier for utilities to transfer such tax credits to parties that could make use of them. In the latest draft RFP PGE states that it will "incorporate an estimated discount on tax

[13] First RFP Report, p 17-18.

[14] NIPPC Comments, p 13.

[15] PGE Reply Comments p 13.

credit benefits in the analysis of resources with utility ownership structures."[16] In its reply comments PGE states that it will monitor market pricing of such credits but expects the discount will be between 5 and 10 percent.[17]

NIPPC advocates for a discount rate of 50 percent because "the market is too unknown" and that the Commission should direct PGE to model sensitivities with various percentages.[18]

While we do think that a discount of fifty percent is high at this point – notably because this is likely much more expensive than the traditional method of retaining the credits in a deferred tax account – we do agree that this uncertainty should be considered. While this does not need to be spelled out at this point in the RFP we will encourage PGE to examine this in the bid evaluation. Depending on the ranking of bids received we may consider either different levels of discount or looking at breakeven calculations (e.g. the amount of the discount would have to be to prefer a PPA solution over a BTA proposal).

Affiliate Bidder

In their comments, NIPPC raises the issue of affiliate participation. This is relevant because PGE has a pending affiliate application in Docket UI 489. While not opining on the application itself NIPPC claims that an affiliate should not be allowed to bid into this RFP or, if allowed, should be treated as a benchmark bid.[19]

In their reply comments PGE notes their outreach with stakeholders and consumer protection guidelines created in the application process.[20] They further commit to treating such affiliate offers as benchmark offers and requiring these bids to be submitted and scored in advance of third party offers and will disclose whether PGE-owned assets are used in the affiliate offer and whether they will be made available to all bidders.[21]

While we are not involved in the affiliate docket and will not opine on that process should the Commission approve the application we think that PGE's proposal in its reply comments is appropriate.

[16] PGE Reply Comments, Draft RFP Appendix N. p 10.

[17] Ibid, p 17.

[18] NIPPC Comments p 9.

[19] NIPPC Comments, p 20-29.

[20] PGE Reply Comments, p 20.

[21] PGE Reply Comments, p 21.

Reserve Rates

NIPPC requests that PGE utilize actual reserve rates that apply to a bid using third party balancing facilities. NIPPC points to Appendix N of the Draft RFP where PGE states that for consistency all offers will be assessed the BPA reserves rate and renewable resources will be assessed BPA's variable energy and balancing services rates while dispatchable resources will be assessed dispatchable energy resource balancing services.[22]

While we are fine with the general application of BPA rates when more detailed data is not available we do believe that PGE should make it clear that these will not be used if a resource can show it will not be assessed such charges and that it can clearly identify what charges will be imposed on the offer. While we think that real changes should be used to the biggest extent possible in the absence of clear information it is acceptable for PGE to use BPA rates.

Permitting Requirements

In their comments, NIPPC notes a bidder comment from a May workshop regarding PGE's permitting matrix. NIPPC requests that PGE confirm its understanding that if a bidder is unable to meet the permitting guidelines in Appendix N it may submit an explanation as to why that is.[23]

PGE did not address this in their reply comments but we would note here that this is also our interpretation of the permitting matrix and is further supported by footnote 4 and 5 on p 4 of Appendix N of the latest RFP draft. Both footnotes read "PGE will allow Bidders to submit a narrative explanation if they are unable to meet the permitting matrix timeline included in this RFP." This is consistent with the process in the 2021 RFP and we expect no change here.

[22] NIPPC Comments, p 11-12.

[23] NIPPC p 41-42.