ORDER NO. 25-279

ENTERED Jul 24 2025

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2371

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2025 All-source Request for Proposals.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED WITH MODIFICATION

This order memorializes our decision, made and effective at our July 22, 2025 Regular Public Meeting to adopt Staff's recommendation in this matter as modified below. The Staff Report with the recommendation is attached as Appendix A.

We adopt one additional condition to our acknowledgment of the company's request for proposals (RFP). Portland General Electric Company staff who had access to highly confidential information in the last RFP may not be on the benchmark team in this RFP. We believe this condition will go some distance towards putting PGE's benchmark bids on equal footing with third-party bidders in the RFP, while still being reasonable to administer.

Second, we modify Staff's RFP Condition 3. Staff's Condition 3 states: "PGE should evaluate bids that do not meet the minimum transmission requirements and may consider and evaluate such bids for the initial short list as well as the final shortlist, with adequate justification." We change the word "may" to "must," so that it reads that PGE "*must* consider and evaluate such bids for the initial short list as well as the final shortlist." We believe that change will ensure that the evaluation and consideration we intend to occur does.

Finally, we adopt Staff's RFP Condition 2 with certain clarifications. That condition reads: "Prior to issuing the RFP, PGE should publish the quantity of its Mid-C rights not used for the delivery of contracted hydro, other firm RA contracts, or specified zero marginal cost energy, and make Mid-C an acceptable delivery point in this RFP, up to the identified amounts." We clarify that PGE's evaluation should include potential contracts and opportunity costs, rather than just contracts in hand. We want to ensure that Mid-C rights are being used in the most productive and efficient manner possible and believe that this evaluation is the way to get that result.

Made, entered, and effective Jul 24 2025.

Letha Tawney
Chair

Les Perkins
Commissioner

Karin Power
Commissioner

ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
REDACTED STAFF REPORT
REGULAR PUBLIC MEETING DATE: July 22, 2025

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: July 3, 2025

TO: Public Utility Commission

FROM: Sandra Namukaya

THROUGH: Caroline Moore and Kim Herb **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2371)
2025 All-Source Request for Proposals.

STAFF RECOMMENDATION:

1. Approve Portland General Electric's Scoring and Modeling Methodology, as modified by the company in Reply Comments, and subject to the additional conditions outlined in this memo.

2. Approve Portland General Electric's Draft of the 2025 All-Source Request for Proposals, as modified by the company in Reply Comments, subject to the additional conditions outlined in this memo.

DISCUSSION:

Issue

1. Whether the Commission should approve Portland General Electric's (PGE) Scoring and Modeling Methodology (SMM), and if approving the SMM, whether to adopt any or all of Staff's additional conditions.

2. Whether the Commission should approve PGE's Final Draft of the 2025 All-Source (AS) Request for Proposals (RFP), and if approving the RFP, whether to adopt any or all of Staff's additional conditions.

Applicable Rule or Law

The Commission's competitive bidding rules (CBRs) are found in OAR Chapter 860, Division 89. Generally, an electric utility must prepare a draft RFP for each resource acquisition or contract that is more than an aggregate of 80 megawatts and five years in length. OAR 860-089-0100(1)(a); OAR 860-089-0250(1).

An independent evaluator (IE) oversees the RFP process "to ensure that it is conducted fairly, transparently, and properly." OAR 860-089-0450(1). The electric company must consult with the IE while preparing its draft RFP, must provide copies of the draft RFP to all parties to the IE selection docket, and must conduct bidder and stakeholder workshops. OAR 860-089-0250(1); OAR 860-089-0450(3).

The draft RFP must include a variety of elements, including minimum bidder requirements, provisions that align the RFP with identified resource needs set forth in the utility's acknowledged IRP, standard form contracts (and language that allows bidders to negotiate terms different from those standard forms), evaluation and scoring criteria, and provisions detailing how the electric company will share information about the bidding process. OAR 860-089-0250(3); OAR 860-089-0400(1).

When the utility seeks Commission approval of its final draft RFP, the IE submits an assessment of that RFP, and the Commission solicits public comment. OAR 860-089-0450(3). The Commission may approve the RFP, with any conditions it deems necessary, if it determines that the RFP "will result in a fair and competitive bidding process." OAR 860-089-0250(5).

"Affiliated interest," as defined in ORS 757.015(6), includes "[e]very corporation and person, five percent or more of which is directly or indirectly owned by a public utility." Affiliated interest contracts are subject to ORS 757.495 and the applicable rules of the Commission. Under OAR 860-089-0300(1)(a), an electric utility may allow affiliates to submit bids in response to an RFP and must be treated in the same manner as other bids.

OAR 860-089-0300(1)(b) dictates that 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 benchmark or affiliate bids and must be screened from the process.

Under OAR 860-0890300(3)(a) – (b) if benchmark bid elements secured by the electric company are not made available to all bidders, the company must provide analysis explaining that decision when seeking RFP acknowledgement and recovery of the costs of the resource in rates.

Analysis

Background
The review of PGE's last RFP, referred to as the 2023 All-Source (AS) RFP, surfaced the need to promptly issue the next RFP to address delays in energy resource procurement. The Commission directed Staff and PGE to use a streamlined process with stakeholder input on potential limited modifications to the 2023 AS RFP to increase the pool of viable/actionable, non-emitting energy bids.[1] With this clarification, the Commission adopted Staff's recommendations which included:

1) Revising the minimum transmission requirements to enable more energy resource bids without firm transmission, or potentially without Conditional Firm (CF) transmission, to PGE's system,
2) Improving the energy valuation methodology by using updated price forecasts, and
3) Allowing Commercial Online Date (COD) up to 2030.[2]

On November 15, 2024, PGE filed an application in Docket No. UM 2357 to begin the 2025 AS RFP process and seeking partial waivers of the Commission's CBRs. The Commission granted a waiver to allow PGE to file its SMM and draft RFP concurrently.[3] On February 5, 2025, PGE initiated this docket to be used for the selection of the IE and PGE's 2025 AS RFP process. On March 4, 2025, the Commission approved PA Consulting as the IE for PGE'S 2025 AS RFP.[4]

On February 20, 2025, Staff held a Stakeholder Workshop to discuss proposed changes to PGE's minimum transmission requirements. The workshop also covered challenges and solutions with RFP design, including extension of COD, use of updated energy forecast prices, and access to confidential and restricted information by PGE Benchmark.[5] Northwest & Intermountain Power Producers Coalition (NIPPC), Obsidian Renewables, Oregon Solar + Storage Industries Association (OSSIA) and PGE filed

---

[1] *In re Portland General Elec. Co.,* 2023 All-Source Request for Proposals, Docket No. UM 2274, Order No. 24-425 at 1 (Nov. 25, 2024).
[2] *Id*. at App. A, Table 1 at 5.
[3] *In re Portland General Electric Co.,* Docket No. UM 2357, Order No. 25-032 (Feb. 5, 2025) (granted a partial waiver to allow concurrent filing of PGE's SMM and the draft RFP).
[4] Order No. 25-089 (Mar. 5, 2025) (approved PA Consulting as the IE).
[5] Staff's Presentation for PGE RFP Workshop (Feb. 20, 2025).

comments on Staff's proposed reforms, and Staff filed updated reforms on April 28, 2025.

During that process, PGE filed its draft RFP on April 17, 2025, and on April 20, 2025, held a Stakeholder and Bidder Workshop as an introduction to the Draft 2025 AS RFP. Stakeholder comments on the draft RFP were filed by Staff, NIPPC, OSSIA, Form Energy, Renewable Northwest (RNW) and PGE Benchmark on May 16, 2025. On May 30, 2025, PGE filed reply comments to stakeholders. The IE filed its assessment of the draft RFP on June 13, 2025.

In this RFP review process, Staff sought to expand the pool of eligible and actionable energy resource bids and focused on three RFP design elements: transmission reforms, updated energy valuation, and a later COD. Staff, PGE, the IE, and stakeholders all identified changes to improve the RFP's fairness and competitiveness. Staff applauds PGE's willingness to collaborate and offer meaningful solutions to reduce transmission-related barriers for bidders. At this stage, Staff and IE find most of the RFP elements are reasonable and straight forward.[6]

Staff focuses this report on the remaining unresolved issues. Staff analyzed these issues and developed a narrow set of conditions to increase the likelihood of a RFP design that results in a "fair and competitive bidding process." OAR 860-089-0250(5). Staff recommends conditions for minimum requirements to extend the COD and expand the acceptable Points of Receipt (POR) to Mid-C. For the other RFP terms and requirements, Staff addresses the reintroduction of the use of Portland Renewable Resource LLC (PRR), interconnection of on-system resources, the use of an execution viability assessment and associated negotiation escrow, tax and tariff uncertainties, credit requirements, various contract elements, and issues of confidentiality and access to information.

PGE's 2025 RFP proposes using the 2023 RFP evaluation process including the following key steps in Figure 1.

[6] IE's Assessment Report on Draft RFP at 20 (June 13, 2025).

Figure 1: 2025 All-Source RFP Analysis Process

<u>Minimum Bidder Requirements</u>

Figure 1 shows that minimum bidder requirements (MBRs) act as an initial "screen" of bids. MBRs were a focus area for Staff because of how transmission and delivery requirements can reduce the bidder pool and have been a persistent issue in PGE's RFPs.[7] PGE's draft RFP began with most of the MBRs from the 2023 AS RFP and was updated to reflect Order No. 24-425. PGE further incorporated reforms from Staff,[8] NIPPC, OSSIA, RNW, and Form Energy. Altogether, PGE's SMM contains eighteen MBRs.[9] Staff focuses on PGE's changes to COD, acceptable delivery points,[10] transmission minimum requirements, and the handling of emerging technologies.

Commercial Online Date

PGE is seeking resources with COD no later than December 31, 2029, to fill potential capacity and energy needs from 2026 through 2029.[11] PGE's RFP makes an exception for long construction lead time technologies and will accept these bids with a COD no later than December 31, 2031.[12]

Staff asked PGE to extend the COD to December 31, 2030, to match and reflect the company's HB 2021 2030 compliance targets.[13] The end of 2030 is in line with Staff's previous recommendation, adopted in Order No. 24-425, that PGE allow resources

---

[7] *In re Portland General Elec. Co, 2018 Request for Proposals for Renewable Resources,* Docket No. 1934, Order No. 18-483 (Dec 19, 2018) ("We now reiterate that the lack of transmission flexibility is a problem insofar as it has limited the projects eligible for the final shortlist in two successive RFPs.").
[8] Staff's Presentation for PGE RFP Workshop (Feb. 20, 2025).
[9] PGE Reply Comments, App. A, SMM at 1-8 (May 30, 2025).
[10] Staff uses the terms delivery points or PODs. PGE sometimes uses the term "points of receipt" or PORs, which may mean the same thing, albeit one is from the perspective of a resource delivering and the other is from the perspective of a utility receiving energy.
[11] PGE Final Draft RFP, Main Document at 4 (Apr. 17, 2025) (PGE's 2025 RFP indicates an energy need of 1,004 MWa through 2029, minus any successful acquisitions in the interim (251 MWa/year). PGE estimates the remaining 2029 capacity need to be between 300 and 500 MW (summer and winter)).
[12] PGE Reply Comments, App. A, SMM at 2.
[13] Staff Comments at 2 (May 16, 2025).

"COD up to 2030."[14] Staff also requested PGE to clarify how projects with earlier COD would be prioritized in the scoring framework under this RFP.

PGE declined to extend the COD to December 31, 2030, arguing that resources coming online at the end of 2030 would have minimum impact on the HB 2021 emissions compliance target given that the reporting requirements consider actual emissions in 2030. The company also responded that an additional year introduces uncertainty while decreasing the likelihood for a project meeting the RFP minimum requirements.

Staff appreciates PGE's efforts to focus on the 2030 compliance need and balance a large bidder pool with the risks of making commitments to resources with greater uncertainty. Given the scale of PGE's resource need pre-and-post 2030 and the level of uncertainty in the energy landscape, Staff continues to find that the December 31, 2030 COD strikes a better balance for three reasons: (1) PGE's proposed end of 2029 COD does not represent an extended COD timeline, (2) non-emitting resources online for part of 2030 can help demonstrate HB 2021 continual progress, and (3) and PGE's next RFP COD could be 2031.

First, the intent of an extended COD was to expand the pool of eligible bids that might help the company meet HB 2021 goals, while aligning with a key planning date for HB 2021 compliance. PGE's COD of December 31, 2029, which expects projects to be online 44 months after the RFP is issued, does not represent an extended COD. In fact, this timeframe is slightly shorter than what was in the company's 2023 RFP, which accommodated bids that would be online 46 months after issuance.

Second, the acquisition of non-emitting resources, even with partial year GHG emission reductions, would yield some 2030 emission reduction benefits and, in a worst-case scenario, projects not operational until later in 2030 could still demonstrate progress towards future HB 2021 compliance dates and provides more options to consider projects that can help meet resource needs in challenging affordability conditions.

Lastly, unless PGE acquires an average of 1,004 average MWa of non-emitting resources in this procurement, it will need to promptly issue another RFP after this one, which might reasonably have a required COD not earlier than 2031.The IE also noted that PGE is operating in a constrained environment marked by transmission limitations on BPA's system and resource needs which may require the company to issue RFPs more frequently in the near future. The IE also noted that allowing bids with a 2030 COD would also provide insight to PGE and the Commission into the market and development pipeline in advance of future RFPs to the extent that this RFP is not able to secure the target resources as well as future needs Therefore, Staff finds that PGE

[14] Order No. 24-425, App. A at 14.

would benefit from an extended COD window not only to meet the HB 2021's 2030 compliance reporting targets but also to demonstrate interim HB 2021 continual progress.

The proposed SMM prioritizes projects with earlier CODs through capacity need timing and higher energy price values forecasted for projects with earlier COD. This reduces the risk of prioritizing later COD projects over earlier ones while allowing a broader range of projects to participate and preserving PGE's ability to meet near-term needs. Staff believes that extending the COD window provides a more flexible and competitive procurement environment aligned with long-term system needs. Staff therefore maintains the recommendation that PGE extends the permitted COD to December 31, 2030, for all conventional resources.

SMM Condition 1: Minimum Bidder Requirements COD should be December 31, 2030, for all conventional resources.

Acceptable Delivery Points
Similar to past RFPs, one of the MBRs states that PGE will accept delivery within PGE's balancing authority area and at BPAT.PGE.[15] To address transmission barriers for bidders PGE includes four delivery points on BPA's system where PGE has existing renewable energy resources (VER PORs) and rights to deliver to its system. Staff supports PGE's additional delivery points for bidders and continues to recommend PGE also accept delivery at Mid-C.

PGE's proposal to include VER PORs is a welcome, and challenging, change to consider. It allows 1,197 MW of new resources to interconnect and deliver to PGE's load, to the extent PGE's existing facilities are generating at less than their nameplate capacity. Staff continues to support PGE's inclusion of VER POR delivery options and sees them as a valuable option for expanding the pool of actionable bids. Staff also appreciates the company's willingness to work with bids that rely on short term redirects by considering those bids conforming and its commitment to work with BPA operators and bidders to enable the success of such bids. Staff views this as an implementable solution on the timeline requested by Staff and a jumping off point for further innovation while constraints on the existing transmission system remain.

While NIPPC recognizes this approach is a positive departure from the status quo, they note several limitations.[16] NIPPC explains that there is limited time for bidders to secure

---

[15] PGE Reply Comments, App. A, SMM at 4, Table 1 (shows all MBRs).
[16] Staff Proposed Minimum Requirements Modifications and Other Changes at 10 (Apr. 28, 2025).

transmission to the locations identified and that PGE could offer more than PORs to help bidders to make the best use of the existing transmission system. NIPPC further suggested that benchmark bids may be better positioned to take advantage of this option in this RFP and that it relies on PGE's discretion to work with BPA to enable use of transmission rights at existing points across benchmark and third-party bidders.[17]

NIPPC suggests that neither benchmark bids nor affiliates should be allowed to use the VER POR options. Instead, NIPPC recommends:

- PGE should allow bidders to make use of PGE assets, such as nearby land and interconnection so they might interconnect through a gen-tie line,
- Benchmarks and affiliates should be subject to a cost adder that is proportional to a bid's share of PGE's transmission costs from VER POR to PGE's system, and,
- The Commission should direct PGE to work in good faith with BPA to enable the use of any excess transmission capacity from the proposed PGE's VER PORs.

PGE asserts that the VER POR option is intended to allow geographically diverse bidders to arrange transmission service within BPA's system to the VER POR points, which will be more feasible than acquiring delivery to PGE's load.[18] PGE's expectation is that some bidders may already have interconnection rights to these locations or are in the process of securing the rights. PGE however recognized BPA's planning pause and proposed allowing bids to provide executable plans to acquiring transmission requirements prior to the final shortlist in November 2025. While PGE committed to working with BPA operators and bidders to address operational complexities, it clarified that securing interconnection rights and gen-tie lines remains the bidders' responsibility even though PGE is open to collaborate with bidders on such efforts. To support third party use of the VER POR option, PGE proposed allowing bidders to be able to use short term redirects to deliver to VER PORs, provided that redirects can be confirmed as viable prior to final shortlist publication and long-term transmission rights are available following the conclusion of the short-term product.

Staff appreciates hearing NIPPCs concerns about the risk of benchmark bids being unfairly advantaged in their ability to use the VER POR delivery option in this RFP. Staff's goal is to leveraging existing transmission rights to secure cost-effective non-emitting energy for customers, whether from utility owned or third party bids. This is

[18] PGE Reply Comments at 10.

undoubtedly in the best interest of customers and an efficient use of rate payer funded assets. Staff understands that presenting a possible VER POR delivery option for which there may be little or no realistic opportunity for third party bidders to use can impact bidder confidence.

At the time of the writing of this report, PGE has not shared information about its expected benchmark bids. Based on PGE's filing for a Site Certification Amendment with the Energy Facilities Siting Council, to request to construct a 385 MW solar facility and a 375 MW battery storage facility at the Biglow location. Regardless of whether PGE plans to bid this as a benchmark or affiliate bid, Staff is disinclined to restrict use of this delivery point option because it sees doing so as also restricting customers options in this RFP.

Staff endeavors to work with PGE and parties to make ongoing improvements to PGE's more flexible transmission approach and believes this these potential limitations with third-party bids ability to use PGE's PORs in this RFP emphasizes the benefits of Staff's proposal to include delivery at Mid-C, a location where the feasibility of competitive third-party bids is enhanced. This is discussed further in the below on Delivery at Mid-C.

Minimum Delivery Amount
In addition, the SMM states that for VER PORs "delivery at any time will only be accepted to the extent existing facilities are generating at less than their nameplate capacity."[19] The IE noted the limitation this presents for "bidder confidence of a minimum delivery amount" at the VER PORs.[20] In reply comments, PGE partially addressed the concern by committing to provide 12x24 historic averages of existing generation.[21]

This limitation with the current approach may also present issues later in contract negotiations, as counterparties typically need to ensure a minimum amount of delivery to secure project financing.[22] The IE recommends that PGE establish clear VER POR specific terms and conditions including providing defined minimum delivery amounts to enhance bidder confidence and reduce ambiguity in the procurement processes.

Staff agrees with the IE and finds this would increase the competitiveness of the RFP. Staff recommends PGE clearly and comprehensively, including 1-2 examples, describe how PGE will contractually guarantee payment for delivered energy in specified month/hour blocks, which would be informed by the generation profile of the existing

[19] PGE Reply Comments, App. A, SMM 2 at 4.
[20] IE's Assessment Report on Draft RFP at 20 (June 13, 2025).
[21] PGE Reply Comments at 12.
[22] IE's Assessment Report on Draft RFP at 20 (June 13, 2025).

resource. The description should also include a clear and comprehensive explanation, including 1-2 examples of *how* the generation profile of the existing resource will be used in identifying the specified month/hour blocks.

RFP Condition 1: The RFP must clearly and comprehensively describe how PGE will contractually guarantee payment for delivered energy in specified month/hour blocks, as informed by the generation profile of the existing resource. The description should also include a clear and comprehensive explanation, with examples, of *how* the generation profile of the existing resource will be used in identifying the specified month/hour blocks.

Delivery at PGE Fossil Resources
Staff offered PGE several additional points of delivery to consider as opportunities to expand the pool of actionable bids, which are described in the next few sections. PGE's argument that transmission rights should be retained for fossil generation and market purchases during hours when additional renewable energy is available to meet load makes Staff comfortable forgoing this option in the near-term and committing to further exploration in subsequent RFPs. When explored in future RFPs, Staff will focus on PGE's policy requirements and the principles of economic dispatch both incentivize PGE to displace fossil generation and market purchases that would otherwise serve load when additional renewable energy is available.[23] Consequently, Staff encourages PGE to move toward transmission-constrained co-optimization of their fossil fuel and renewable fleets in the future to reduce both the costs and emissions associated with meeting their load.

Delivery at Mid-C
While Staff is comfortable tabling it's other point of delivery suggestions for further discussion, allowing delivery at Mid-C is a viable near-term option to address NIPPC competitive concerns and address delays in its energy procurements. Staff agrees with PGE that transmission rights delivering existing non-emitting generation to PGE load,

---

[23] Regarding economic dispatch, because renewables are a zero (or negative) marginal cost resource, they are generally lower cost in operations to take available renewable energy than to pay for the fuel and O&M costs of fossil generation or to pay for market purchases (if market prices are above $0/MWh). The renewable energy should have zero marginal costs for the PPA options because the utility agrees to take whatever energy is delivered to the accepted POD at the PPA price (i.e., they can't refuse the energy when market prices are lower than the PPA price under a typical PPA contract). For the ownership option, it might actually be negative marginal cost if, for example, the project output gets the PTC (so forgoing the output costs the utility money in the form of lost tax benefits). The only time this logic breaks down is when market prices are negative. In this circumstance, the utility might prefer to purchase energy from the market instead of taking their zero or negative marginal cost renewable energy. However, because they have a policy requirement, they'll probably still prefer to take their renewable output before unspecified market purchases, which have associated emissions under HB 2021, in these circumstances (even though in these zero and negative priced hours the region is generally awash with clean energy).

including Mid-C hydro contracts, should continue to serve that purpose. However, Staff notes that if PGE has zero marginal cost energy delivering to Mid-C in the future, it should prefer to bring that energy to its load over making unspecified purchases at Mid-C. PGE's 2023 IRP notes that the company holds 788 MW of transmission rights from Mid-C.[24] Staff also notes that even though some of the Mid-C contracts are set to expire in 2030 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff understands this to mean that the company likely has rights from Mid-C that are not already reserved for bringing specified zero marginal cost energy to their load. Staff believes Mid-C is a location at which PGE could meaningfully and strategically leverage its existing rights and accommodate VERs.

If any of PGE's existing contracts at Mid-C have a variable cost component (at index or some pre-specified price) without a take-or-pay requirement, PGE will save money by not taking that energy when renewable energy delivering to Mid-C is available instead. From an economic perspective, PGE's use of transmission rights from Mid-C to BPAT.PGE to bring renewable energy home should be preferred overusing those rights for market purchases.

In considering the potential for PGE to allow delivery to Mid-C, Staff also referred to Puget Sound Energy's (PSE) recent RFPs that have allowed and stated a preference for delivery to Mid-C.[25] Staff understands that PSE has different planning considerations from PGE, but notes that some of PSE's motivations for allowing deliveries to Mid-C are also applicable to PGE. In particular, PSE notes that delivering project output to Mid-C allows them to utilize their existing transmission rights from Mid-C to more directly support resource adequacy, relative to a strategy in which their rights from Mid-C primarily provide access to the market. PSE refers to this as "firm[ing] up" their transmission rights with resources.[26] Staff finds this logic and approach to be reasonable and in customer interests to the extent that it promotes delivery of additional resources that meet specific customer needs (both resource adequacy and policy compliance) over existing transmission rights that would otherwise only be used for market access.

Furthermore, while PGE seeks to retain more flexibility to use their transmission rights from Mid-C to minimize their operational costs, economic dispatch principles suggest that if zero marginal cost renewable energy is available at Mid-C, delivering that energy

---

[24] Docket No. LC 80, PGE's 2023 Integrated Resource Plan at 226, Figure 67.
[25] See https://www.pse.com/en/pages/energy-supply/acquiring-energy/2025-2026-Capacity-and-Firm-Energy-RFP.
[26] See Slide 5at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=871&year=2024&docketNumber=240004.

to load will be lower cost (in positively priced hours) and will make greater contributions to policy compliance (in all hours) than using those transmission rights to deliver unspecified market purchases to load. PGE may instead be seeking to retain their flexibility to use those rights for purposes other than meeting load (for example accessing arbitrage opportunities). However, from Staff's perspective, meeting customer needs with utility assets should take priority over such activities.

RFP Condition 2: Prior to issuing the RFP, PGE should publish the quantity of its Mid-C rights not used for the delivery of contracted hydro, other firm RA contracts, or specified zero marginal cost energy, and make Mid-C an acceptable delivery point in this RFP, up to the identified amounts.

Impact of Market Seams

In response to the request for additional points of delivery, PGE raised concerns regarding potential day-ahead market seams between BPA and PGE. PGE argues that BPA's announcement to join Markets+ creates uncertainty about the ability of an entity delivering to an EDAM-based Load Serving Entity, like PGE, to purchase and use BPA non-firm transmission products that may otherwise be prioritized for intra-market deliveries.[27]

Staff shares PGE's concern about the potential implications of market seams on the availability of short-term firm transmission rights. But from conversations with the IE, Staff understands that the market seams issue is not expected to disrupt PGE's ability to use its existing LTF rights in a manner supporting Staff's proposal.

The IE suggests PGE proactively identify additional PORs with transmission products, conditions, and delivery restrictions similar to those identified for PGE's proposed VER PORs. Doing so can provide PGE and stakeholders with increased visibility to potential market dynamics, pricing, and the development pipeline for those locations. Further, this might help ensure PGE and stakeholders have necessary data to appropriately react to market changes as EDAM and Markets+ are implemented. Staff looks forward to working with the company on this for future RFPs.

Transmission Minimum Requirements

PGE incorporated feedback from Staff, stakeholders, and Order No. 24-425 to reduce requirements for long term firm transmission (LTF) by 1) differentiating transmission requirements for dispatchable and non-dispatchable resources, and 2) reducing the minimum transmission requirement for non-dispatchable renewable resources from

[27] PGE Reply Comments at 13.

75 percent of the interconnection limit to 75 percent of the Qualifying Capacity Contribution (QCC) for the resource type and location.[28]

Minimum Requirements for Dispatchable Resources
PGE maintains the minimum transmission requirements for dispatchable resources at 100 percent of the resource's interconnection limit set in PGE's 2023 RFP.[29] RNW recommended that PGE eliminate this transmission requirement for dispatchable and hybrid resources. NIPPC sought clarification regarding the transmission products acceptable for dispatchable resources and proposed that PGE accept bids using conditional firm transmission.

PGE responded that the 100 percent LTF transmission requirement would only apply to standalone dispatchable resources. PGE stated this limit ensures that the resources can reliably deliver energy when called upon. Staff continues to support PGE's requirement for 100 percent LTF for dispatchable resources due to the reliability and capacity purposes of a dispatchable resource.

PGE's VER PORs Minimum Transmission Requirement for Renewables
PGE's 2025 Draft RFP proposed that renewable projects delivering to VER PORs secure transmission rights for 100 percent of the project interconnection limit to the VER POR. NIPPC and RNW objected to this requirement, noting that it placed more stringent minimum transmission requirements on renewables delivering to VER PORs than renewables delivering to PGE's system.[30] In Reply Comments, PGE agreed to align the minimum transmission requirements for projects delivering to VER PORs with those for renewable projects delivering to PGE's system. Staff appreciates PGE's responsiveness to stakeholder feedback and supports PGE's revision.

Treatment of Non-conforming Bids - Busbar
Staff and NIPPC urged PGE to evaluate bids that do not meet the minimum transmission requirements, including busbar products, and not to necessarily preclude inclusion of these bids on the short list,[31] while NIPPC, OSSIA, and RNW proposed lifting all minimum transmission requirements. Stakeholders' proposal is based on Staff's recommendation for PGE to explore using its existing, available transmission

---

[28] PGE Reply Comments at 8, fn.9 (QCC values are "based on analysis conducted by the Western Resource Adequacy Program (WRAP) and depend on the resource type and location. Values specified as of RFP issuance will not be updated during the RFP process or the duration of construction and operations."): PGE Reply Comments, App. A, SMM at 55, Table 2 (showing the calculated minimum transmission requirement by resource type and zone).
[29] PGE Reply Comments at 9.
[30] NIPPC Draft RFP Comments at 4; RNW Draft RFP Comments at 10.
[31] Staff Proposed Minimum Requirements Modifications and Other Changes at 10, item c (Apr. 28, 2025); Staff's Opening Comments at 4 (May 30, 2025).

rights and leveraging short-term purchases. PGE objects to both Staff and NIPPC's proposals, saying that projects that do not meet the minimum transmission requirements may appear to be lower cost, but instead reflect less developed projects with that have deliverability and reliability risks.[32]

Staff views the evaluation of bids that do not meet the minimum transmission requirements as helpful for price discovery as the company evaluates the cost and risk tradeoffs of different transmission arrangements. The IE also highlights that non-conforming bids could provide value to customers as well as help PGE meet its HB 2021 goals.[33] The IE recommends that PGE consider allowing competitive bids that are non-conforming on the basis of not meeting the minimum transmission requirements onto its final shortlist.[34] Staff supports this condition as a way to increase the competitiveness of the RFP. Staff does not suggest that PGE should be expected to necessarily include bids that do not meet the minimum transmission requirements on the final short list if they are not otherwise considered competitive bids.

One reason that Staff supports this condition is because of alternate transmission options for PGE to bring new resources online. Staff notes that PGE's current long term firm transmission assets portfolio, estimated at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** PGE's current peak load capacity of approximately 4,500 MWa and available resource nameplate capacity of 4,629 MW (2023 IRP).[35] Additionally, PGE's IRP preferred portfolio includes over 1,750 MW of incremental storage as early as 2029 when the preferred portfolio resources peak to over 8,000 MW.[36] Given this trajectory solely on transmission criteria would unnecessarily narrow the pool of viable bids. PGE's own data reflects that the company's LTF rights far exceed its load forecast obligations even with a 20 percent buffer.

RFP Condition 3: PGE should evaluate bids that do not meet the minimum transmission requirements and may consider and evaluate such bids for the initial short list as well as the final shortlist, with adequate justification.

Emerging Technology Requirements
PGE's 2025 RFP seeks technologies that are commercially proven and have been deployed at scale. RNW, PGE Benchmark, and Form Energy highlighted the value of

---

[32] PGE Reply Comments at 6.
[33] IE's Assessment Report on Draft RFP at 19 (June 13, 2025).
[34] *Id.* at 24.
[35] PGE Roundtable meeting presentation at 22 and 24 June 4, 2025 CEP/IRP Roundtables | PGE.
[36] PGE Roundtable meeting presentation at 22 & 24 June 4, 2025 CEP/IRP Roundtables | PGE.

emerging technologies like the 100-hour storage batteries in terms of energy, capacity and flexibility and emphasized the need to adequately value these attributes in the RFP.[37] RNW and Form Energy recommended that the RFP encourage the participation of emerging technology developers to bid into this RFP and also get selected to the FSL if found to be least cost and least risk. RNW and Form Energy propose that the RFP allow for alternative ways of demonstrating commercial viability and scale for emerging technologies beyond existing deployments.[38] RNW and Form Energy also propose that the RFP expands the list of acceptable dispatchable resources to include iron-air battery and compressed air storage technology and that it provides clarity on the capacity accreditation of multi-day storage resources like the 100-hour iron air batteries.

In Reply Comments, PGE indicated it supports and will implement changes to the RFP main document and the SMM that are responsive to concerns about language and scoring that hampers the participation of emerging technologies. This includes updating the ELCC calculator to show indicative capacity values for multi-day energy storage, which is based on proxy resource assumptions in PGE's 2023 IRP Update.[39]

Staff appreciates PGE's willingness to adopt language that supports accommodation of emerging technology.

Scoring and Modeling Valuation

Energy Valuation
PGE makes a welcome change to how it values future energy from projects by relying on the company's 2023 IRP Update energy forecast. This means the RFP modeling will forecast resource production and utilize the reference case market price forecast from the most recently filed IRP Update, inclusive of available natural gas price forecast updates.

PGE's use of the energy forecast methodology it used in the 2023 IRP Update is responsive to Commission Order No.24-425. Staff and NIPPC also recommended the company conduct a sensitivity analysis on the energy valuation. Staff expects to work with the company on what sensitivity analyses will be conducted after the RFP is issued, including one for forecasted energy values. Staff appreciates the company's willingness to use a methodology that has not yet been included in an acknowledged IRP and notes that its use as part of the scoring of this RFP should not be seen as a substitute for the review and analysis that takes place as part of the IRP or IRP Update.

---

[37] RNW Comments at 2-3; PGE Benchmark Comments Pg. 8; Form Energy Comments at 2-5 (May 16, 2025).
[38] RNW Comments at 2-3; Form Energy Comments at 2-5 (May 16, 2025).
[39] PGE Reply Comments at 5: LC 80, 2023 IRP Update at 179, Tables 36 and 37 (June 18, 2025).

Approach to Transmission Risk
Staff, supported by NIPPC, recommended that PGE develop an evaluation methodology for transmission risk based on historical path congestion data adopted from Sylvan's report.[40] In Reply Comments, PGE declined, and instead proposes a "Transmission Derating Methodology," discussed below.[41]

Staff also requested additional information about how transmission risks would be managed, and whether PGE would secure short-term transmission for project output that exceeds the LTF rights secured for the project or made available by PGE. In Reply Comments, PGE confirmed that bidders would be responsible for securing transmission over the course of the contract.[42] PGE states that projects have the "responsibility for * * * acquisition of additional service for ongoing generation."[43]

It is still not clear to Staff how this allocation of transmission risk may affect the competitiveness of this RFP. For example, Staff is unsure whether bidders will be able to use the additional transmission flexibility in this RFP by having lower LTF or eligible conditional firm requirements, and also showing that they can procure monthly short-term transmission to cover the remainder of project output. Although the practicality is uncertain, Staff finds that the allocation of transmission risk from a RFP design perspective is fair, because utility owned projects and PPAs are both treated the same, as both a PPA and a benchmark bears the responsibility of making transmission arrangements.

Staff appreciates PGE's efforts to develop a transmission risk analysis and evaluation methodology, and generally supports the methodology PGE has put forward. Staff urges PGE to incorporate similar transmission risk analysis into future IRPs and to refine this analysis in future RFPs as conditions evolve and more information becomes available.

Energy Derating Methodology
PGE will model generation associated with LTF as fully deliverable. Because the RFP allows a portion of a project to not have LTF service, PGE proposes a method of assigning a lower value to the energy supplied above projects' LTF rights. PGE states that it will first clip or "derate" energy deliveries in hours when short term transmission

[40] "*Toward a more holistic and adaptive treatment of BPA transmission rights in Northwest utility planning and procurement processes,"* GridLab and Sylvan Energy Analytics (March 2025), available at: https://gridlab.org/wp-content/uploads/2025/04/Sylvan-and-GridLab_Renewables-Transmission-Rights.pdf.
[41] PGE Reply Comments at 30.
[42] PGE Reply Comments at 7.
[43] PGE Reply Comments at 15.

products will likely not be available.[44] For the remaining energy that likely can be delivered with short term transmission, PGE proposes a "cost attribution" or adder, for the cost of short-term transmission. Because the details of this methodology are slightly different for deliveries to BPAT.PGE vs. the VER PORS, and for PPAs vs. utility-owned, Staff asked many questions on this topic to evaluate potential bias in the methodology, and ultimately finds the methodology appears to support a fair and competitive bidding process.

Initial Derating for Energy Beyond LTF

PGE's energy derating methodology first applies LTF availability adjustments to projects, whether delivering to BPAT.PGE or a VER POR.[45] PGE uses a monthly and hourly heat map based on high flows (over 80 percent of total transfer capability), from 2023 to present, on specific BPA flowgates used to deliver to BPAT.PGE. Staff was concerned that applying derates to energy delivered over LTF, even when no historical curtailment has occurred, could discourage viable renewable bids. However, PGE projects the impact of the derating as only "approximately 2% to 4% reductions in energy value."[46] Staff finds that this impact should not affect the competitiveness of the RFP.

Staff's second concern was that PGE would not consider conforming transmission products such as system conditions (SC) or number of hours (NH) as part of the LTF portion of the project. PGE addressed this concern, stating that LTF and "or eligible conditional firm" products will count as fully deliverable.[47]

Staff's last concern with the energy derating was whether PGE customers would face more risk from a utility owned project under performing versus a PPA that is only paid for energy delivered to load.[48] In conversations with the Company, PGE clarified that it will make the derating calculation equal for PPA and utility owned bids, and that both PPAs and utility owned bids will be evaluated with a "net cost expressed in real levelized $/MWh."[49]

For PPAs, PGE will use the described derating methodology to estimate hourly project output adjusted for transmission curtailment risk. This derating will reduce the bid's energy value. Because PGE will not pay for energy that is curtailed due to a

[44] PGE Reply Comments Appendix A at 30
[45] Id.
[46] Id. at 32.
[47] Id. at 31.

[48] PGE Reply Comments Appendix A at 31-32.
[49] Id 31.

deliverability constraint, Staff anticipates that bidders will account for transmission curtailment risk by increasing the price of their bids. PGE will not estimate short term transmission cost adders for PPAs because securing short term transmission to support the deliverability of the project will be the responsibility of the bidder, and is assumed to be included in the PPA price.

For owned resources, PGE will use the same derating methodology to estimate hourly project output adjusted for transmission curtailment risk. Similar to PPAs, this derating will reduce the bid's energy value. After the derating and the cost attribution (discussed below), PGE will convert benchmark resources so that all resources have a cost in $/MWh."[50]

The risk that Staff considered is whether a utility owned resource would look more competitive in the RFP, when down the road it would be more expensive in a rate case that includes the full cost of the project regardless of output. However, because the derating applies the same to PPAs and utility-owned bids, and both will be converted to $/MWh, the comparison should be fair. Staff is committed to working with the IE to ensure that the cost comparison does not underestimate the curtailment risk of utility owned projects.

Cost Attribution
For utility-owned resources only, PGE will estimate additional costs associated with securing short-term transmission to deliver project output to PGE that exceeds the bid's LTF rights, because PGE will be responsible for managing the deliverability of the project output. PGE refers to this as a cost attribution adder for the energy that should be deliverable with short term products. The cost attribution that PGE will use for utility-owned resources will apply BPA tariff-based rates to model transmission costs for short term products. As noted above, all PPA bids will need to reflect the price of delivering to BPAT.PGE, accounting for transmission costs, transmission products, and appropriate curtailment risks. Staff was concerned that a benchmark resource may underestimate the additional transmission costs to gain an advantage in the RFP. However, PGE responded that the cost attribution will use BPA's most up-to-date monthly and hourly non-firm rates.[51]

Capacity Valuation
PGE updated its method for valuing capacity for bids using VER PORs, and bids using conditional firm system conditions transmission products, and updated its ELCC calculator, which is used to help bidders estimate the capacity contribution their bids

[50] Id. at 15.
[51] PGE Reply Comments at 33.

would receive. Staff is supportive of PGE's current proposed capacity valuation under this RFP.

Alternative POD Capacity Valuation
PGE's capacity value methodology will account for both the dispatchable and non-dispatchable nature(s) of the bid, as well as the transmission product provided by the bidder. For resources that deliver to a VER POR, PGE proposes to model the output of renewable off-system resources as an addition to existing PGE generation at that location, up to an appropriate operational threshold based on PGE's transmission rights associated with that POR. Staff supports this approach as a way to recognize the contribution of diverse resources to resource adequacy without over-estimating the resource adequacy contributions of energy deliveries that have elevated transmission risk. For resources delivering to Mid-C, Staff recommends that PGE cap the project output for the purposes of calculating capacity contributions by the difference between PGE's LTF rights from Mid-C to BPAT.PGE and the capacity available to meet PGE load from PGE's hydro contracts delivering to Mid-C.

Mid-C Capacity Valuation
If PGE allows the inclusion of Mid-C as a POR, the company should value capacity following Staff's guidance in Staff's proposed RFP recommendations report.[52] Specifically, PGE should not assign incremental value to such bids unless PGE holds transmission rights in excess of the maximum output of the corresponding firm contracts.

Conditional Firm – System Conditions Capacity Valuation
Stakeholders including NIPPC, PGE Benchmark, OSSIA, and RNW raised concern regarding PGE's prior valuation of capacity for conditional firm-system conditions (SC) transmission rights. They argued that the last RFP undervalued SC transmission products by assigning zero capacity value to these products while applying an annual curtailment of 50 percent to conditional firm number of hours. RNW highlighted that system conditions products have historically faced low to no curtailment coincident with PGE's peak demand hours, and therefore PGE scoring should assume that system conditions products are conditionally curtailed on a comparable basis to the number of hours transmission in the absence of a company provided curtailment risk assessment.[53] NIPPC, OSSIA, and RNW also note that currently there are no alternative transmission products to systems conditions for resources delivering to PGE's territory making no capacity allocation to such products impractical.[54]

---

[52] Docket No. UM 2371, Staff Recommended reforms for PGE RFP at. 10-11, April 28, 2025
[53] RNW Comments at 11; NIPPC Comments at 19.
[54] NIPPC Comments at19; OSSIA Comments at 3.

Staff appreciates PGE's willingness to attribute capacity value to system conditions transmission equivalent to number of hours assumptions. PGE added that this revision may be revisited in future IRPs and/or RFPs, if more granular analytical approaches are available. Staff views this reform as progress towards the Commission directive to increase the pool of eligible bids given that some developers had viewed this as an undervaluation of their resource's capacity and hence a deterrence to bidding.

ELCC Calculator Update
To provide more clarity to stakeholders on capacity valuation as a result of the updated transmission minimum requirements, PGE updated its ELCC calculator to incorporate 2023 IRP Update assumptions; include indicative capacity values for proxy resources as a function of size, transmission amount, and transmission product; and reflect multi-day storage. Staff appreciates the company's responsiveness to updating this tool, which is intended to help provide transparency around how capacity is valued.

Flexibility Valuation
PGE's flexibility value estimates the value a resource brings to PGE's system by responding to forecast errors, enabling fast ramping, and meeting reserve requirements. The flexibility values employed are the same as those from the 2023 RFP except that PGE's 2025 RFP flexibility value will be scaled proportional to LTF transmission availability for any hybrid resources in which battery nameplate capacity exceeds long-term firm transmission rights.

Alternative Valuation – System-wide Benefits
Form Energy suggested that PGE's approach of considering energy, capacity, and flexibility value overlooks the value of avoided capacity benefits driven by resource interactions such as long-duration and multi-day storage technologies.[55] They argued that PGE should evaluate bids based on a consideration of the difference between total system costs of a portfolio with and without a proposed project. Form Energy recommended this portfolio optimization modelling include consideration of capital cost savings from avoided resource requirements, operating cost savings from reduced fuel consumption and operations and maintenance, and deferral benefits from delayed transmission and distributions investments.

PGE did not comment on this suggestion, but Staff finds the suggestion compelling given that long duration storage has historically struggled to compete in RFPs. Staff is not recommending this RFP change its valuation method to align with Form Energy's proposal but proposes working with PGE and the IE to see whether such an analysis

[55] Form Energy Comments on PGE's RFP at 2-5 (May 16, 2025); Staff's Opening Comments Pg. 8 (May 16, 2025).

could be conducted or approximated to inform the effectiveness of evaluation for long duration storage projects.

Other RFP Terms and Requirements

Re-introduction of PRR
Evolving policy guidance and legislative uncertainty have reignited concerns about the ability of customers to access the full benefits of tax incentives when investor-owned utilities own solar and storage resources. In response, PGE has included the provision from 2023 RFP[56] that would consider bids from resources owned by a PGE affiliate through a power purchase agreement with Portland Renewable Resource LLC (PRR).

Staff requested the company clarify how the RFP timeline and scoring and modeling would be updated to reflect the review of potential PRR bids and whether the contract with the IE contemplated analysis and reporting regarding the impact of PRR bids on the FSL. PGE Benchmark sought clarity about the availability of the PRR options to non-solar, ITC eligible resource projects, such as storage.

In PGE's reply comments, the Company highlighted that the 2023 RFP bid forms had incorporated the Commission guidance for which PGE has carried forward in the 2025 RFP hence no significant change has been made regarding the adoption of PRR in this RFP.[57]

PGE also clarified that the PRR bid scoring would be undertaken in accordance with the Commission guidance ensuring that third party BTA/APA bids are received, scored, and sealed prior to PGE receipt of third-party bids. PGE acknowledged that adopting PRR would indeed impact RFP milestone dates and proposed a revision of the RFP schedule as shown in Table 1 below, but will not impact the current RFP timelines.

Table 1. Bid Due Date Schedule Adjustments

Milestone	Current Proposal	Revised Proposal
Benchmark bids due	~~28-Aug-25~~	21-Aug-25
Third-Party BTA/APA bids due	12-Sep-25	12-Sep-25
All other bids due	26-Sep-25	26-Sep-25

[56] Docket No. UM 2274, Order No. 24-011 (Jan. 12, 2024).
[57] PGE Reply Comments at 21-22.

Responding to PGE Benchmark's recommendation, PGE acknowledged that energy storage had not originally been included in the PRR due to its exclusion from IRA opt out provisions and that it intended to change the language to include any ITC eligible bids, including storage. PGE clarified that no new provisions were being made to the PRR options currently and PRR would only be used in case of a change in law that required ITC normalization.[58] PGE did not clarify whether a change in the IE contract was necessary in their reply comments.

Staff notes that the reintroduction of PRR option may provide flexibility in structuring affiliate transactions in light of the changing ITC transferability rules under the IRA. However, it is not clear to Staff whether these provisions will increase the pool of bids. Staff is also concerned about the amount of time available to review the proposed inclusion of storage within the PRR scope given that it had not been previously considered under the PRR framework in 2023 RFP. It's unclear whether any additional changes or conditions would need to be considered to ensure a fair and competitive process. As such, Staff does not support the expansion of PRR eligibility to include storage, given the effort to limited changes to this RFP.

Staff emphasizes that to the extent that PRR provisions are utilized in this RFP, PGE should adhere to the Commission's PRR conditions established in UM 2274, Order No. 24-011. PGE should also specify the changes in law that would trigger reintroduction of ITC normalization for affiliate bids. PGE should commit to consulting with IE and Staff immediately should such a change occur.

SMM Condition 2: PGE's execution of PRR negotiations and contracts in this RFP should adhere to the Commission's PRR Participation Conditions in Order No. 24-011.

On-System Interconnection Requirements
PGE's requirements for interconnection is the same for both on-system and off-system bids:

- An active generation interconnection request in the transmission provider's interconnection queue.
- A completed system impact study by the transmission provider with active participation in PGE's 2025 transitional cluster study process being deemed conforming.

[58] PGE Reply Comments at 21-22.

- If interconnection involves a 3rd party other than the transmission provider, the bid must also include an interconnection request to the third party and all associated studies.

Further, PGE requires on-system resources interconnecting to PGE's system to be studied as Network Resource Interconnection Service (NRIS), whereas off-system resources can be studied as Energy Resource Interconnection Service (ERIS) or Network Resource Interconnection Service.

RNW requested that on-system resources be allowed to use ERIS as an alternative to NRIS given that it can reduce interconnection costs and bottlenecks due to associated lower costs and can get connected more quickly.[59]

PGE Benchmark proposed assigning incremental location value to on-system standalone storage bids given that the line and load study results will not be used to inform bid scores.[60]

PGE declined RNW's proposal to allow on-system generators to be studied as ERIS. PGE argues that an NRIS interconnection request is intended to identify upgrades required for the deliverability of a resource to load. ERIS interconnection requests, alternatively, require a sperate transmission service request process to get surface this information.[61]

PGE responded that the company would not apply general or specific locational adders to storage bids as proposed by PGE Benchmark. PGE notes that transmission and load study requirement for on-system resources are intended to provide actionable information about resource deliverability, even if distribution-connection resources may reduce wheeling costs.

Staff recognizes PGE's interest in requiring NRIS for on-system resources to the extent that it supports informed decisions about the timing and cost of resources expected to be deliverable to load. Staff is also interested in understanding more about how to appropriately consider and value ERIS and distribution connected resources in an RFP but recommends that be a topic for consideration for a future RFP.

In addition to the issues mentioned above, Staff finds the requirements to be overly restrictive for certain on-system bids that are not part of the active transitional cluster

[59] RNW Comments Pg. 7-8, May 16, 2025.
[60] PGE Benchmark Pg. 5, May 16, 2025.
[61] PGE Reply Comments at 23.

study process, but that have been part of the serial queue process and are able to otherwise demonstrate required network upgrade costs and studies supporting CODs.

In PGE's last RFP, the IE Closing Report identified ten storage projects that were in the process of attempting to interconnect to PGE's system.[62] The 2023 RFP required projects to have a completed System Impact Study upon bid submission and a completed Facilities Study upon selection to the final shortlist.[63] The Report explained that PGE's interconnection process experienced extensive delays. As a result, many of the listed projects could not meet these requirements despite having been in the queue for a good deal of time. The IE noted significant uncertainty regarding the process for projects in the serial queue migrating to the transitional cluster and communicated to PGE that projects in the queue should continue to be considered, as they appeared to have pathways to meeting the required 2027 COD. The PGE RFP evaluation team agreed and proposed continuing to evaluate all of the projects, and committing to returning to the discussion should any be considered for the FSL. Ultimately some of these projects were competitive enough to be considered for the FSL, but PGE ultimately decided to categorize them as non-conforming due to issues around the interconnection requirements.

Staff sees this as a potential missed opportunity to secure competitive bids. Akin to how PGE allows bidders to demonstrate alternative paths to demonstrate transmission, Staff believes allowing bidders alternative documentation to demonstrate interconnection milestones such as cost and COD, expands the pool of actionable bids. Staff recommends that on-system bidders with documentation of network upgrade costs and appropriate COD timing may be deemed eligible, despite not conforming with interconnection minimum requirements for the specific interconnection studies.

For on-system projects, Staff proposes that bids not otherwise meeting PGE stated minimum interconnection requirements[64] must demonstrate an achievable plan to meet the following interconnection requirements:

- Interconnection in-service date anticipated by November 30, 2030, demonstrated by:
    - Having an active interconnection queue request in study with PGE or an executed LGIA with PGE; or

---

[62] UM 2274 PGE's Request for Acknowledgment of the Final Shortlist of Bidders in Portland General Electric Company's 2023 All-Source Request for Proposals – Appendix A Independent Evaluator's Final Report on Portland General Electric's 2023 All Source Request for Proposals p 14 – 15.
[63] 2023 RFP Appendix N p 5 and p 14.
[64] See PGE's Table 1 Minimum Bidder Requirements, page 4.

 - Defining a point of interconnection on PGE's system and, if shortlisted, attesting to enter PGE's first inaugural interconnection cluster study to commence in the first quarter of 2026.
- As a further safeguard against speculative bidding, PGE could require a shortlist security posting for bids not currently in the queue to ensure only credible bidders proceed into the cluster study process for 2026.

RFP Condition 4: On-system bidders with documentation of network upgrade costs from the serial queue and appropriate COD timing may be eligible, despite not being in PGE's current transitional cluster.

Execution Viability
PGE is proposing to evaluate "execution viability" before the ISL and later the FSL. The company describes it as a qualitative and information only assessment based on seven factors that include: interconnection agreement status, permitting status, credit requirements, major equipment supply plans, construction plans, and tax and tariff change in law provisions.

OSSIA and Staff raised a concern that the introduction of an additional evaluation criteria seems to go beyond the scope of the proposed minimum modifications as indicated in the Commission Order No. 24-425.[65] In addition, NIPPC was concerned that PGE had not yet completed the rubric of the viability framework and hence it was premature and should not be adopted.[66]

While opposed to the timing of the introduction of this approach, NIPPC, OSSIA, and PGE Benchmark are not opposed to the components of the viability criteria. The stakeholders propose that the factors should instead be adopted as non-price score if the Commission deemed it fit to keep this evaluation framework. OSSIA raised concerns regarding the appropriateness of some elements of the viability criteria such as construction, the maturity of which could be hard to demonstrate at the time of bid submission.[67]

RNW and OSSIA are opposed to the use of the execution viability scoring criteria to determine a negotiation escrow, with the argument that this penalizes successful bidders.[68] PGE Benchmark is supportive of the introduction of the evaluation framework and proposed inclusion of additional elements on risk mitigation.[69]

---

[65] OSSIA Comments at 11 (May 16, 2025); Staff's Opening Comments at 9.
[66] NIPPC Comments at 30 (May 16, 2025).
[67] OSSIA Comments at 11 (May 16, 2025).
[68] RNW Comments at 6-7 (May 16, 2025); OSSIA Comments at 11 (May 16, 2025).
[69] PGE Benchmark Team Comments at 3 (May 16, 2025).

PGE explained that top performing bids in the past RFPs (2018, 2021, and 2023) were unable to execute contracts due to challenges related to commercial maturity milestones. PGE further said that "the removal of non-price scoring in the 2023 RFP reduced PGE's ability to register and communicate identified viability risks," which have increased uncertainty to contract execution.[70] PGE asserts that the focus to expand the pool of eligible bids necessitates the need to mitigate viability and maturity risks early, and specifically cites Staff's proposals for the 2025 RFP, which recommends elimination of transmission requirements and extension of the COD, as contributing factors in this uncertainty. Lastly, PGE in reply comments said its proposed framework should not be seen as new evaluation criteria, saying it "layers onto the RFP without modifying its core evaluation structure including scoring and selection methods."[71]

Staff finds that PGE's inclusion of a framework for execution viability provides increases transparency in the company's consideration of 'actionable' projects. Staff notes that there appears to be general alignment among stakeholders about the value of having this type of information and the scope of issues proposed to be included in the framework. The main area of disagreement is regarding whether it is appropriate to use execution viability scores as a determining factor for assessing and apply a negotiation escrow.

Staff appreciates some of the company's arguments about the value of including evaluation for execution viability. Project attributes such as firm transmission and relatively near-term CODs can signal project maturity. The IE notes that viability issues will likely increase and persist given the current uncertainty around supply chain, tariff, and the policy environment, hence supports the inclusion of an execution viability framework to track project maturity.[72]

In this RFP, the company has signaled its willingness to expand the types and amount of transmission projects that would be required to have secured to participate and be considered for evaluation, as well as a willingness to extend the COD. However, Staff disagrees with PGE that the 'layering' of this framework should not be seen as a change in RFP scoring. Regardless of whether PGE uses it to determine the application of a negotiation escrow or as a non-price score, Staff views a framework for considering these aspects of a projects as part of how a project is ultimately scored. Insofar as PGE expands its consideration of transmission attributes and COD as discussed above, Staff would support the inclusion of an Execution Viability framework as a new non-price scoring element of the SMM, as discussed further in the **Non-price Scoring Alternative** section.

[70] PGE Reply Comments at 16.
[71] PGE Reply Comments at 15.
[72] IE's Assessment Report on Draft RFP at 21 (June 13, 2025).

The company's claim that the lack of an execution viability framework in past RFPs and the removal of non-price scoring have negatively impacted contract execution may be reasonable. However, Staff sees both capturing this information in the execution viability framework *and* using it to effectuate the need for a negotiation escrow as an unnecessary step to mitigate the project maturity risks it identified. Staff discusses this further in the section below on **Negotiation Escrow**.

Negotiation Escrow
PGE's 2025 RFP introduces a negotiation escrow payment for projects selected to the FSL that are deemed to have any viability shortcomings based on the execution viability framework. PGE's proposed escrow payments are; $150,000 for projects with total nameplate capacity of 40 MW or less, and $300,000 for projects greater than 40 MW.

NIPPC, RNW, and OSSIA objected to the escrow payment arguing that they were ambiguous and not attached to any quantifiable costs and that such payments penalized successful bidders.[73] NIPPC also argues that introduction of escrow payments may result in high-cost bids where bids may raise the prices of their bids to cover the payment.[74]

In Reply Comments, PGE acknowledges that the escrow payment fees are not a function of any particular risk and a bidder that narrowly falls short of one of the elements is identical to one that misses all the six.[75] PGE notes that the framework was designed to avoid complex calculation of the escrow amount and is a guardrail for bids "…for whom real feasibility and schedule concerns remain following months of detailed back and forth communications between PGE, the bidder and the IE PGE."[76]

PGE described the touchpoints for developing, curing, and updating the viability factors informing whether an escrow payment is needed:

1. Pre-ISL Assessment. Viability factors are assessed in initial bid scoring through consultation with the IE. Bidder has opportunity to take mitigating actions and/or provide relevant additional information to PGE as part of their Best and Final Offer submission.
2. Pre-FSL Assessment. Viability factors are re-assessed prior to final shortlist finalization through consultation with the IE.

---

[73] Docket No. UM 2371, PGE RFP Comments; Renewable NW Comments Pg 6-7; NIPPC Comments Pg 29 – 31; OSSIA Comments Pg 11, May 16, 2025.
[74] Docket No. UM 2371 PGE RFP NIPPC Comments Pg 29 – 31 May 16, 2025.
[75] PGE's Reply Comments Pg. 19, May 30, 2025.
[76] Docket No. UM 2371, PGE Reply Comments, Page 19, May 30, 2025.

3. Escrow Determination. If a bidder does not satisfy one or more viability factors, PGE will request an escrow payment in an acceptable form.
4. Escrow Retention. PGE will retain the escrow payment if PGE enters into negotiations with the bidder. Otherwise, PGE will refund the escrow at the conclusion of the 2025 RFP process, within 30 days of PGE's RFP Results Publication regulatory filing.[77]

PGE agrees with NIPPC's concern that the escrow payment requirement may not rule out the chances of a negotiation escrow payment being passed on to customers.[78] The company, however, declined to make modifications to the negotiation escrow element on the pretext that "…viability risks are real, and projects with unmitigated viability risks present a higher likelihood of falling through in the negotiation phase, increasing negotiation costs and decreasing PGE's ability to efficiently reach agreements with viable projects."[79]

PGE states that in the 2018, 2021, and 2023 RFPs, top performing bidders were unable to execute contracts with PGE due to shortcomings related to the commercial maturity of the projects. Staff appreciates the challenges of ensuring bidders submit projects priced to accurately reflect project commercial maturity. IE notes that a negotiation escrow can ensure counterparties enter negotiations in a serious manner is not unheard of in utility procurements, but also that it is not a common practice. In the event that the Commission takes on the proposal, the IE recommends having clear guidelines to ensure it is not abused.

Finally, Staff notes that Idaho Power proposed a similar escrow provision, described as a Supplemental Fee, in the 2026 All Source RFP and the Commission chose to reject it.[80] Review of the contract negotiations in the IE Contract Negotiations Report shows no indication that the absence of this provision resulted in the Company having to negotiate with non-viable bids. …

Given the tradeoffs on both sides of this proposal, Staff considered two options. First in recognition of PGE's willingness to consider potentially riskier bids, Staff considered a recommendation that lowers the escrow amount to a much less burdensome level. Second, Staff considered consistency with past Commission decisions and concerns about deterring bidders if the Commission accepts this element. Staff returns to the goal of expanding the pool of actionable bids. In this case, Staff understands the company's

[77] Docket No. UM 2371, PGE Reply Comments, Page 18. May 30, 2025.
[78] Docket No. UM 2371, PGE Reply Comments, Page 19, May 30, 2025.
[79] Docket No. UM 2371 PGE Reply Comments, Page 19, May 30, 2025
[80] Docket No. UM 2255, Order No. 23-260, Idaho Power's 2026 All-Source RFP, App. A Pg. 13 July 17, 2023.

concern about the 'actionable' aspect being diminished if bidders submit unmature projects. However, Staff is concerned that the negotiation escrow could limit bidders and believes the information captured in the execution viability non-price score can help reduce the risk of advancing apparently cheaper but ultimately non-viable/non-conforming projects.

SMM Condition 3: The Negotiation Escrow payment element should be removed from the RFP.

Non-price Scoring Alternative
NIPPC, OSSIA, and PGE Benchmark recommended that the elements of the execution viability framework be included as a non-price scoring factor to account for execution viability and awarded points or weights. NIPPC and OSSIA proposed adopting a 10 percent non-price score while PGE Benchmark recommended 20 percent non-price score.[81]

PGE acknowledges that the execution viability elements can be converted into a non-price score and proposes a rubric based on the RFP's Appendix F that could translate the total score possible points to 1000. PGE, however, did not propose adoption of the non-price scoring but remained open to Staff and IE recommendations while noting that no significant change in bid selection was observed during previous non-price scoring framework.[82]

The company points to the lack of a non-price score as one of the reasons for including the execution viability framework but argues that converting execution viability framework to a non-price score should not be seen as mitigating the problems the negotiation escrow is intended to address.[83]

Staff appreciates feedback from stakeholders on how to adopt the viability criteria in the scoring. Staff agrees with the IE that the non-price score may provide an avenue to track and cure viability challenges. While prior RFP scoring undertaken with a combination of both price and non-price score elements did not result in significant impact on project selection,[84] Staff believes that assigning a non-price score in this instance could mitigate viability risk early in the process. This may especially be the case with the new reforms being proposed in this RFP. Staff therefore supports

---

[81] Docket No. UM 2371 PGE RFP Stakeholder comments; NIPPC Comments at 31; OSSIA Comments at 11: PGE Benchmark at 3, May 16, 2025.
[82] PGE Reply Comments, Pg 19, May 30, 2025.
[83] PGE Reply Comments, Pg 19, May 30, 2025.
[84] Docket No. UM 2274, Order No. 24-011, App. A at 12 (Jan. 12, 2024).

stakeholders' proposal of incorporating the execution viability factors into a non-price score and adopting a 10 percent weight to execution viability.

If supported by the Commission, Staff commits to working with the IE and PGE throughout the execution of the viability framework to reduce subjective evaluation and ensure reasonableness of PGE's evaluation results. Appendix A shows the draft rubric developed by the IE.

SMM Condition 4: Include Execution Viability as a non-price score using 10 percent proposed weighting.

Tariffs and Tax Credit Uncertainty

In Opening Comments, Staff and stakeholders raised concern about the how the uncertainty around federal tax credits and tariffs pose great risk to project viability and cost assumptions. Staff recommended PGE collect more information on tax assumptions and that PGE conduct a sensitivity analysis to test the assumed policy uncertainty and the impact of changes in federal tax credits.

OSSIA and PGE Benchmark emphasized the importance of mitigating tax credit risk and recommended a non-price scoring for projects that have demonstrated physical progress or qualify for pre-end of 2028 legacy section 48 ITC through "safe harbor."[85]

In Reply Comments, PGE shared similar concerns about federal tariff and tax uncertainties. PGE intends to collect a broad range of updated bid information in the November 2025 Best and Final Offer step. PGE explains that it expects bidders to base their bids on the current policies and to proactively manage future tariff risk through supply chain decisions.[86]

The Company proposes a set of changes reflective of comments from Staff and OSSIA. PGE proposes to require a description of tariff mitigation strategies from bidders. This would include full details of a bid's tax and trade assumptions, as well as risk exposures. PGE proposed an additional execution viability criteria factor to account for the reasonableness of proposed commercial terms that might be impacted by these uncertainties, noting especially whether redlines in terms shift costs to customers. While PGE deferred committing to specific sensitivity regarding tax credit impact, PGE commits to working with IE and Staff during the evaluation phase to identify appropriate sensitivity scenarios.[87]

[85] OSSIA Reply Comments, Pg. 11 – 12, May 16, 2025, and PGE Benchmark Reply Comments, Pg 5, May 16, 2025.
[86] PGE Reply Comments at 20 (May 30, 2025).
[87] PGE Reply Comments at 26 (May 30, 2025).

In addition to the elements described by PGE, the IE recommends that PGE require bidders to:

- Specify the amount of tax credit, including potential energy community or domestic content bonus credit under the federal Investment Tax Credit (ITC), that is assumed in its bid pricing.
- Provide a percentage breakdown by major component of the countries that components are originating from and ensure that bidders submit their tariff mitigation strategies with their bids.

Staff supports PGE's approach, as updated with the IE's additional recommendations, to capturing, considering, and managing tariff and tax credit uncertainty.

Change in Law Provisions
Given the current volatility of federal policies particularly surrounding the IRA tax, ITCs, PTC and tariffs, stakeholders have raised concerns about the adequacy of risk sharing mechanism in 2025 RFP which would ultimately impact bid prices. OSSIA and NIPPC emphasized the importance of including Change in Law provisions in PPA and BTA form contracts to address the current challenges which may force them to price in significant uncertainty.[88] OSSIA specifically proposes including a 60-day renegotiation period with an optional termination right and a 20 percent termination payment of pre-COD security.[89] While NIPPC argues for narrow change in law provisions to maintain the benefits of PPA that have locked in terms, conditions and prices but recommends that any provisions accorded to utility owned resources should also be extended to third party bids to ensure equal treatment.[90]

PGE Benchmark recommends that in the event of changes to the IRA prior to the BAFO, the 2025 RFP should allow bidders to update their prices to reflect changes.[91] PGE Benchmark also proposed modifications to BTA form agreements related to cost sharing mechanism, limited change orders due to change in law, as well as termination events.

While PGE acknowledges stakeholder's concern on the severity of uncertainties in federal policies, PGE does not propose specific Change in Law provisions to the form contracts but proposes to make modifications in the term sheet evaluation of proposed

[88] OSSIA Comments, Pg. 8 – 9; NIPPC Comments, Pg. 35 May 16, 2025.
[89] OSSIA Comments at 8-9 (May 16, 2025).
[90] Docket No. UM 2371 NIPPC Comments Pg.35 -36.
[91] Docket No. UM 2371 PGE Benchmark Comments, Pg. 8 May 16, 2025.

redlines as well as the execution variability framework to reflect mitigation of tariff and tax uncertainties.

The company elaborated on its planned use of term sheet redlines in its response to the PGE Benchmark's request to have formal scoring, which PGE declined to adopt. The company reiterated and clarified that it intended to "…report on commercial disagreements with respect to non-firm transmission curtailment risk and price change risk related to change in law or tariffs via the viability assessment." The company also explained it would provide feedback to bidders about their initial execution viability assessments before the BAFO update.[92]

Staff appreciates this additional clarification as to the translation of some of the term-sheet redline aspects into the viability assessment and agrees with the company's approach of working with the IE and Staff on ensuring the viability assessment appropriately captures term sheet redlines (and non-firm transmission curtailment risk). Given that Staff sees this as scoring that risks being subjective, this close oversight on the part of the IE and Staff will be critical.

Staff supports suggestions by NIPPC and OSSIA to consider impact of changes in federal tariff and policy and make necessary provisions to allow reasonable price adjustments and cost recovery in response to tax and tariff regimes for both utility-owned and third-party bids. Staff supports PGE's effort to track and ensure tariff uncertainties are adequately mitigated without transferring all the risk to rate payers.

SMM Condition 5: PGE should work with the IE to ensure that all commercial terms include reasonable change in law provisions that equitably allocate risk among counterparties without shifting excessive risk to ratepayers.

Credit Requirements
PGE Benchmark and OSSIA provided a number of credit requirements related recommendations. Particularly OSSIA recommends that PGE expands its acceptable security requirements in the form BTA and PPA to include surety bonds. PGE's draft RFP credit requirements require cash or letter of credit.[93] OSSIA argued that Surety bonds provide the same financial assurance that letters of credit provide while reducing the costs of assurance and allowing access to cheaper capital.[94]

In Reply Comments, PGE committed to accepting surety bonds as a form of security and acknowledged their potential to reduce project cost. PGE, however, noted that

[92] Docket No. UM 2371 PGE Reply Comments, Pg.20–21, May 30, 2025 .
[93] See Appendix I of PGE's Draft RFP April 17, 2025.
[94] Docket No. UM 2371, OSSIA Comments, Pg 7 – 9 May 16, 2025.

since this is a new product, it would require additional review and consultation with the IE before fully adopting the recommendations to Appendix I (Credit Requirements).

Staff appreciates the company's willingness to consider expanding credit requirements to include surety bonds as an option and understands that the company will work with the IE on how it can consider and include this option.

OSSIA also requested that PGE reduce, remove, or delay bidder security and creditworthiness or other financial qualifications in an effort to expand the pool of bidders and reduce bid prices. They argue that projects are not financed based on their balance sheet but on the project viability and economics.[95]

PGE declines this change, saying while it may increase the pool of bids, it does not help prioritize inclusion of viable bids and results in a loss of valuable information about a project's viability. It notes that without security posting when a project is listed on the initial shortlist, PGE loses valuable information about bid viability. Staff agrees that OSSIA's proposed change might expand the pool of bids but agrees with PGE that the expansion might not necessarily be of bids that are actionable.

PGE Benchmark recommended modifications to security and creditworthiness information that would increase to some of the security requirements. PGE notes that costs may be reduced due to modifications to guarantee backout damages based on PGE Benchmark's suggestions. Staff does not see this change as something that would increase the pool of actionable bids and recommends against this additional modification at this time. that high security amounts may be a barrier to bidders hence at the moment rejects any consideration of PGE to increase security costs unless there is justifiable rationale that should be communicated earlier on in the process.

Alternative Acquisitions Structure

OSSIA proposed that PGE expand its RFP framework to accommodate flexible alternative bid structures; "programmatic bids" and a "Fast track" alternative bid option both designed to accelerate clean energy resources acquisition and improve market access.[96] Specifically:

- Programmatic bids would allow developers to propose a portfolio of projects across multiple sites rather than a single site based on a schedule over time, and
- Fast track bids would bypass negotiations if it met certain criteria bypassing the need for protracted RFP process, negotiation risks and transaction costs.

---

[95] Docket No. UM 2371, OSSIA Comments, Pg 7 – 9 May 16, 2025.
[96] OSSIA Comments, Pg 12 –13, May 16, 2025.

In Reply Comments, PGE acknowledges the merits of OSSIA's proposal of distribution-connected project bids that could satisfy minimum requirements but declines to adopt the proposal in this RFP due to its overreaching scope.[97] Staff agrees with PGE that adopting these structural changes at this stage would require material revisions that are outside the scope of the proposed recommendations of this RFP. Staff however, notes that these approaches may be particularly valuable in enabling more diverse and resilient clean energy portfolio and encourages that PGE explore these approaches during the design of its next RFP.

Contracts

Warranties and Long-Term Service Agreements
The current PGE 2025 RFP requires that utility ownership bid have an associated LTSA in place for a minimum of five years. NIPPC recommended that the RFP specifies minimum requirements for *Long-Term Service Agreements (*LTSAs) and/or warranties for all utility ownership bids that will ensure equal contractual protections as the PPA and BSA bids. NIPPC also recommended that in place of minimum requirements, that appropriate cost adders should be considered with support of the IE.[98] PGE's Benchmark also proposes modifications to the LTSAs and warranties including capacity performance for energy storage bids and warranties for utility owned bids.[99]

In Reply Comments, PGE argues that an LTSA requirement corresponding to the life of a resource does not correspond to a least cost least risk option for customers. PGE, however, was open to feedback from the IE regarding how to incorporate appropriate cost and risk assumptions in bid scoring. PGE also reiterates that they will consider specific bid information prior to the BAFO.

The IE agrees with PGE that requiring a LTSA for the full term of a resource may not be the best option. The IE believes that LTSA period of 5 years may be too short, however a 10-year minimum may result in better value. Staff supports IE 's position and recommends PGE adopts a 10-year minimum LTSA given that this reduces risk to rate payers. The IE and PGE should therefore review the justification for shorter LTSA durations as well as ensure that all LTSA costs and risks are appropriately included.

Term Sheets
PGE Benchmark proposes that redlines in term sheets should be incorporated as part of the scores to discourage low prices bids with unfavorable terms. PGE declined this

---

[97] PGE Reply Comments, Pg 23, May 30, 2025.
[98] NIPPC Comments, Pg.37, May 16, 2025.
[99] PGE Benchmark Comments, Pg.9, May 16, 2025.

request arguing that the execution viability framework will enable PGE to evaluate the commercial viability where upon an opportunity will be provided too bidders to rectify any disagreements.

Staff agrees with PGE's position and notes that incorporating redlines into the scoring framework would introduce an additional subjective criterion into the SMM which affects transparency in bid evaluation. Staff supports maintaining a clear and objective scoring and modelling framework and encourages resolution of term sheet issues during negotiation and review phases rather than through bid scoring.

Non-Disclosure Agreements
NIPPC raised concerns about the revisions to the non-disclosure agreements revisions made by PGE regarding stakeholder access requesting revisions that would acquire obtaining bidder consent to access confidential information. In Reply Comments, PGE confirmed that the NDA revisions are intended to remove the need for bidder consent to provide confidential or highly confidential bid information to other stakeholders in other dockets in the context of data requests under appropriate protective orders.

NIPPC also noted that PGE had updated the term of the NDA back to two years after the Commission decision to use a five-year term NDA which does not provide sufficient protective cover.[100] In response, PGE clarified that the reduced term was covering the RFP period and removes the excess management and the legal risk across five years.

Staff supports NIPPC's concerns and recommends that PGE returns the NDA term to five years as directed by Commission in support of Staff recommendations of protecting bidder data and the integrity of procurement process given how close the RFP process have been recurring over the past years.

RFP Condition 5: The RFP should reflect a five-year non-disclosure agreement term.

REC Retention Option
PGE updated the 2025 RFP requirements in response to staff recommendation to allow bidders to provide a price with or without RECs with no penalty. PGE updated its language in its redlined RFP Scoring and Modeling Methodology (Appendix A) regarding Qualifying Products to say:

> PGE shall be the offtaker for all output from the resource or portion of the resource bid into this RFP. Resources must include all power attributes

[100] Docket No. UM 2166, Order No. 21-460 at 7 (Dec. 10, 2021); see also Docket No. UM 2274, Order No. 24-011, Appendix A at 67.

> associated with the resource, including associated renewable energy credits (RECs), environmental attributes, energy benefits, and capacity benefits. Additionally, Bidder may provide a bid variant in which the Bidder retains rights to all RECs generated by the project. PGE will prioritize acquisition of REC-inclusive products to fulfill PGE's 2040 RPS need.

PGE has not provided additional information about the company's REC needs to support the value in prioritizing REC-inclusive bids. Staff is sees the company's inclusion of language regarding a prioritization of REC-inclusive bids as akin to a penalty against those that do not bring RECs, but understands the value of articulating possible preferences for evaluation purposes. Staff will work with the IE and the company to understand how the company will consider tradeoffs as it evaluates REC-inclusive bids.

Benchmark Resources and Staffing

Confidentiality and Information Access

Stakeholders and Staff have raised concerns over PGE Benchmark team access to confidential bidder information or other confidential IRP data not otherwise available to third party bidders. Staff addressed this concern in Staff's proposed recommendations to the 2025 PGE RFP reporting to include quarterly disclosure of the current and past roles of all staff members participating on a benchmark or affiliate team and their associated access to certain confidential information in past RFPs and IRPs.[101] This topic is also being considered in AR 669 in the context of CBR rule changes.

NIPPC reiterates its earlier recommendation for the Commission to include more proactive measures beyond Staff's proposed monitoring to ensure compliance to this requirement as well as include information in Staff's disclosure chart on whether a Benchmark team staff signed an applicable protective order.[102]

The IE also reechoes the CBR provisions that resources should not be reassigned between the RFP review and development and the Benchmark team.

Staff appreciates NIPPC's feedback but declines to recommend further monitoring compliance actions beyond those in Staff's proposal, AR 669 and OAR 860-089-0300(1)(b). Staff will continue to use information requested in Staff's disclosure chart (Appendix 1 Staff's Proposed Recommendations to PGE's RFP) with

[101] Docket No. UM 2371, Staff's recommendations for PGE RFP Pg 7-8 April 28, 2025, and Staff's Opening Comments, Pg 10, May 16, 2025.
[102] Docket No. UM 2371, NIPPC Comments at 26.

the help of the IE to ensure compliance with the CBRs and uphold fairness of the competitive bidding process.

While PGE provided Staff and the IE information details of the RFP and Benchmark development staff names and roles, the company is yet to provide all the information recommended by staff for disclosure chart such as the past roles in RFP or IRP processes.

Staff recommends that PGE provides quarterly disclosure of the current and past roles of all staff members participating in a benchmark or affiliate team and their associated access to certain confidential information in past RFPs and IRPs.[103]

Benchmark Resources
Staff and NIPPC noted that PGE had not yet provided the information on Benchmark bid elements to allow for comparative analysis of affiliate bid evaluation. NIPPC reasons that PGE has failed to satisfy a CBR that requires a utility that plans to submit a benchmark resource into the RFP and not make elements of the benchmark bid available to all bidders, to provide an explanation as to why they are not making the elements available in their draft RFP.[104] NIPPC recommends that PGE is forbidden from submitting bids in this RFP given that contrary to CBRs the Bid assets have not been vetted by stakeholder s for reasonableness.

OAR 860-089-0010(1) states the purposes of the CBRs are to “establish a fair, objective, and transparent competitive bidding process. PGE’s upfront disclosure of benchmark characteristics would provide transparency, consistent with other requirements in the CBRs that increase transparency. A similar proposal that requires PGE to disclose is in AR 699 as well as OAR 860-089-0300. Staff at this moment does not support NIPPC’s interpretation of the CBR with associated recommendation to bar PGE from submitting bids into this RFP. Staff as highlighted by the IE recognizes the ambiguity in the CBR about the timing of submitting Benchmark elements to the RFP. However, Staff encourages PGE to update the RFP Appendix L with Benchmark bid elements and allows stakeholders to provide feedback before RFP acknowledgement to allow potential bidders review the appropriateness of this information.

RFP Condition 6: PGE provides quarterly disclosure of the current and past roles of all staff members participating in a benchmark development as PER Staff’s proposed disclosure chart.

[103] Staff’s Opening Comments on PGE RFP Table 1, Pg 11, May 16, 2025.
[104] OAR 860-089-0300(2)-(3).

RFP Condition 7: PGE updates the RFP Appendix L with Benchmark bid elements and allows stakeholders to provide feedback before RFP acknowledgement.

<u>Conclusion</u>

Based on the above analysis, Staff believes PGE's Draft 2025 Scoring and Modeling Methodology and All-Source Request for Proposals should be approved as fair and competitive, subject to the conditions recommended by Staff. Below is a summary of Staff's conditions.

Staff's SMM Conditions

SMM Condition 1: Minimum Bidder Requirements COD should be December 31, 2030, for all conventional resources.

SMM Condition 2: PGE's execution of PRR negotiations and contracts in this RFP should adhere to the Commission's PRR Participation Conditions in Order No. 24-011.

SMM Condition 3: The Negotiation Escrow payment element should be removed from the RFP.

SMM Condition 4: Include Execution Viability as a non-price score using 10 percent proposed weighting.

SMM Condition 5: PGE should work with the IE ensure that all commercial terms include reasonable change in law provisions that equitably allocate risk among counterparties without shifting excessive risk to ratepayers.

Staff's RFP Conditions

RFP Condition 1: The RFP must clearly and comprehensively describe how PGE will contractually guarantee payment for delivered energy in specified month/hour blocks, as informed by the generation profile of the existing resource. The description should also include a clear and comprehensive explanation, with examples, of *how* the generation profile of the existing resource will be used in identifying the specified month/hour blocks.

RFP Condition 2: Prior to issuing the RFP, PGE should publish the quantity of its Mid-C rights not used for the delivery of contracted hydro, other firm RA contracts, or specified zero marginal cost energy, and make Mid-C an acceptable delivery point in this RFP, up to the identified amounts.

RFP Condition 3: PGE should evaluate bids that do not meet the minimum transmission requirements and may consider and evaluate such bids for the initial short list as well as the final shortlist, with adequate justification.

RFP Condition 4: On-system bidders with documentation of network upgrade costs from the serial queue and appropriate COD timing may be eligible, despite not being in PGE's current transitional cluster.

RFP Condition 5: The RFP should reflect a five-year non-disclosure agreement term.

RFP Condition 6: PGE provides quarterly disclosure of the current and past roles of all staff members participating in a benchmark development as PER Staff's proposed disclosure chart.

RFP Condition 7: PGE updates the RFP Appendix L with Benchmark bid elements and allows stakeholders to provide feedback before RFP acknowledgement.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric's 2025 All-Source Request for Proposals with the RFP Conditions recommended by Staff.

Approve the associated Scoring and Modeling Methodology with the SMM Conditions recommended by Staff.

Appendix A – Non-Price Score Draft Rubric[105]

Viability Factor	Purpose	PGE FSL Expectation	Assessment questions	IE Proposed recommendation for Adjusting to Non-Price Framework	Reference
Interconnection Agreement	Confirm Bidder has accounted for or minimized risk of uncertainty related to timing and cost of interconnection including associated upgrades; reduce risk of COD-related bid drop-out.	Interconnection agreement has been tendered or executed by the time PGE files the final shortlist.	1a. Has Bidder provided proof that an interconnection agreement has been tendered and/or executed? (Y/N)	0 points - no agreement 1 point - facilities agreement 2 points - tendered and/or executed interconnection agreement	(SMM requires completion of a Facilities Study. Tendered agreement establishes a timeline commitment.)
Transmission Responsibility	Confirm Bidder understanding of PGE's commercial and operational expectations regarding arrangement of transmission service and assumption of delivery risk; reduce risk of negotiation failure due to irreconcilable commercial positions.	Bidder understands PGE commercial terms regarding deliveries in excess of Long-Term Firm or Conditional Firm transmission.	2a. Has Bidder reviewed applicable term sheet(s) and form contract(s) and provided a redline mark up of commercial terms reflected in their bid price, in which the Bidder retains responsibility for delivery risk? (Y/N), or 2b. Has Bidder otherwise confirmed acceptance of commercial terms regarding Bidder retention of responsibility for delivery risk? (Y/N)	0 points - bidder has not provided redlines 1 points - bidder has provided redlines 2 points - bidder has accepted PGE's commercial terms, indicating no changes / redlines	(See 1.16-1.17 of 2023 RFP Bid Form.)

[105] Through the RFP comment process, a tax and tariff uncertainty viability factor was identified as a necessary component of the non-price scoring. The IE's proposed recommendations for adjusting the execution viability framework to a non-price framework utilizes PGE's draft execution viability framework, and therefore the tax and tariff uncertainty factor has not yet been defined by PGE. The IE will work with PGE and Staff to define the tax and tariff uncertainty factor and associated scoring to reduce subjectivity.

Viability Factor	Purpose	PGE FSL Expectation	Assessment questions	IE Proposed recommendation for Adjusting to Non-Price Framework	Reference
Permitting Status	Confirm Bidder has accounted for or minimized risk of uncertainty related to timing and viability of acquiring necessary permits; reduce risk of COD-related bid drop-out.	All permits, studies and surveys indicated in Exhibit A of Appendix A applicable to the project.	3a. Has Bidder met (or received exemption from via narrative explanation) all applicable Final Short List permitting requirements? (Y/N)	0 points - bidder has not received any FSL required permits 1 point - bidder has achieved 50% or more of FSL required permits 2 points - bidder has achieved 100% of FSL required permits	(SMM requires FSL permits by time of FSL filing. Timing affected but no additional requirement.)
Credit Requirement	Bidder demonstration of ability to obtain project financing; reduce risk of complications to negotiations due to project financing uncertainty.	Bidder has met PGE's Final Shortlist Eligibility credit requirement (including demonstration of performance obligations through letter of credit or guaranty if required).	4a. If Bidder's project financing plan includes balance sheet financing, has Bidder met PGE's investment grade credit terms? (Y/N), and/or 4b. If Bidder will not balance sheet finance, has Bidder provided a copy of a Letter of Credit from a financial institution or a parent guarantee? (Y/N)	0 points - bidder did not provide a project financing plan 1 point - bidder provided a project financing plan 2 points - bidder meets PGE's investment grade credit terms or has provided a copy of a Letter of Credit from a financial institution or parent guarantee	(SMM requires Letter of Credit by time of FSL acknowledgement. Timing affected but no additional requirement. See 3.9 of 2023 RFP Bid Form.)

Viability Factor	Purpose	PGE FSL Expectation	Assessment questions	IE Proposed recommendation for Adjusting to Non-Price Framework	Reference
Equipment Supply Plans	Bidder demonstration of reasonably mature plan to procure equipment for use in project, accounting for expected timing and cost; reduce COD-related risk associated with supply chains and construction schedule.	Bidder has demonstrated plans to source major equipment for the project.	5a. Has Bidder provided evidence of project-related communications or a (redacted) quote from an OEM or vendor for all major equipment components (modules, turbines, battery cells, inverters, substation transformers)? (Y/N)	0 points - bidder has not provided a major component / equipment procurement plan or evidence of quotes from vendors for major components. 1 point - bidder has provided procurement plan for major components / equipment or has provided quotes for at least 50% of major components / equipment 2 points - bidder has provided procurement plan for major components / equipment and has provided quotes 100% of major components / equipment Major components / equipment defined as: modules, turbines, battery cells, inverters, and substation transformers.	(See 2.11 of 2023 RFP Bid Form. Also see 6.19-6.20.)
Construction Plans	Bidder demonstration of reasonably mature plan to complete project construction activities, under the planned timing and cost; reduce COD-related risk associated with construction schedule and logistics.	Bidder has demonstrated plans to complete project construction, including understanding of construction schedule and PGE labor requirements.	6a. Has Bidder provided evidence of project-related communications or a (redacted as necessary) agreement with an EPC or site contractor confirming understanding of schedule and PGE labor requirements? (Y/N)	0 points - bidder did not provide project schedule or evidence of EPC agreement affirming COD 1 point - bidder provided detailed project schedule or evidence of EPC agreement affirming COD 2 points - bidder provided detailed project schedule and evidence of EPC agreement affirming COD	(See 6.20 of 2023 RFP Bid Form.)

Appendix B – PRR Participation Conditions from UM 2274

PRR Participation Condition 1: PGE will provide the IE a list of all employees working as part of the RFP team, the Benchmark team, and any employees performing duties on behalf of PRR, including the roles, and associated dates of their work for the various teams at the time it files its benchmark score, at the time it files its FSL, and again after it has completed negotiations for all PRR bids.

PRR Participation Condition 2: PRR participation in this RFP is conditional upon Third-Party ITC-e bids being treated in a similar manner as benchmark bids.

PRR Participation Condition 3: PGE must publish in the RFP, its formula for forecasting PPA prices as part of the RFP evaluation for ISL / FSL selection as well as its methodology and/or formula for converting BTA / APA costs to PPA as a condition of PRRs inclusion in the RFP.

PRR Participation Condition 4: ITC-e bidders are allowed to include a forecasted PPA price in their bid that the IE can compare with the forecasted price calculated by the RFP team and the ultimate PPA price resulting from executed BTA/APA contract terms and conditions.

PRR Participation Condition 5: RFP Evaluation team is responsible for converting BTA/APA prices to PPA prices.

PRR Participation Condition 6: The PRR Form PPA should remove Section 2.5 regarding the option to purchase or extend terms.

PRR Participation Condition 7: PGE must remove Section 8.4 from the PRR Form PPA.

PRR Participation Condition 8: PGE shall align Pre-COD and Security Delivery amounts across PPA and EPC/APA contracts.

PRR Participation Condition 9: The PRR Form PPA must specify that PGE Benchmark team employees are explicitly excluded from the list of Receiving Party Representatives.

PRR Participation Condition 10: Transmission requirements in the form contracts shall match those specified in the RFP.

PRR Participation Condition 11: PRR PPA must include a value for the transmission upgrade cost cap.

PRR Participation Condition 12: PRR PPA must include a value for the Transmission Scheduling of Energy Effective Date.

PRR Participation Condition 13: PGE shall eliminate blanks for PRR PPA performance guarantees.