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

Erin E. Apperson
Assistant General Counsel

September 13, 2021

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street Southeast, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: UM 2166 – In the Matter of Portland General Electric Company, Application for Approval of an Independent Evaluator for 2021 All-Source Request for Proposals

Dear Filing Center:

Enclosed for filing today in the above-referenced docket is Portland General Electric Company's ("PGE") Reply Comments. This document is being filed by electronic mail with the Filing Center.

Thank you in advance for your assistance.

Sincerely,

Erin E. Apperson
Assistant General Counsel

EEA:dm
[Enclosure]

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 2166

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Application for Approval of an Independent Evaluator for 2021 All-Source Request for Proposals.	**PORTLAND GENERAL ELECTRIC COMPANY'S REPLY COMMENTS**

I. Introduction

Portland General Electric Company (PGE or Company) is pleased to submit the following Reply Comments to suggestions and questions received regarding PGE's proposed Request for Proposals (RFP) Scoring and Methodology Proposal. PGE appreciates the comments received from Public Utility Commission of Oregon Staff (Staff), Northwest & Intermountain Power Producers Coalition (NIPPC), Oregon Solar + Storage Industries Association (OSSIA), and the questions received from bidders who have reviewed PGE's Scoring and Methodology Proposal.

PGE remains committed to successfully initiate and complete the 2021 All-Source RFP to procure new renewable resources and non-emitting capacity resources necessary to deliver customers a reliable, affordable, and clean energy future. PGE recognizes HB 2021's mandate to promptly deliver a drastically decarbonized power portfolio to PGE's customers and identifies this planned procurement as essential to make necessary progress toward that aim. While the passage of HB 2021 has not prompted PGE to revise its 2019 Action Plan within this proceeding, PGE strongly agrees with comments received that the planning environment has changed, resulting in an increased urgency to meet the robust decarbonization compliance requirements in 2030. To that end, PGE anticipates building off of the 2019 Action Plan to reduce long-term costs and risks for PGE's customers.

In this solicitation PGE intends to procure renewable resources and non-emitting dispatchable resources to close PGE's elevated 2025 capacity deficit. Upon procurement of approximately 150 MWa of renewable resources consistent with PGE's 2019 Action Plan, PGE will evaluate whether costs and risks can be further reduced though procurement of additional renewable resources to place PGE firmly on track to meeting its forecasted carbon-free compliance requirement. At this time, PGE forecasts approximately 650 MWa of additional renewable resources necessary to meet HB 2021's 2030 compliance requirement. In addition, PGE intends to procure sufficient capacity resources necessary to close PGE's forecasted 2025 capacity deficit of approximately 375 MW.

PGE's Reply Comments are organized into the three primary sections: RFP Procurement Targets, PGE Needs Update and RFP Design Considerations.

II. RFP Procurement Targets

A. HB 2021

Comments received by Staff and OSSIA include discussion and questions focused on PGE's 2021 All-Source RFP procurement targets. Both Staff and OSSIA seek to better understand the alignment of those targets with recent changes to Oregon's energy policy. In particular, Staff and OSSIA's comments focus on the changes associated with the passage of HB 2021 and question whether a procurement that remains in lockstep with the 2019 Integrated Resource Plan (IRP) Action Plan enables PGE to achieve the CO2 reduction requirements now mandated in Oregon.

Staff's comments identify a concern that PGE may face challenges in achieving an 80% reduction in CO2 emissions by 2030 if PGE does not make significant progress toward meeting this requirement through this solicitation.[1] Staff notes that the passage of HB 2021 has established a significant need for additional non-emitting resources and seeks answers to questions regarding the remaining procurement opportunities available to meet this compliance obligation.[2] To that end, Staff posed nine questions that PGE has endeavored to address in these comments.[3]

OSSIA's comments also stress the need to procure significant volumes of non-emitting resources to meet the 2030 and 2040 HB 2021 compliance requirements.[4] To assist in identifying the necessary actions to comply with HB 2021, OSSIA recommends that PGE include in this docket a clear initial plan to comply with HB 2021's major carbon compliance requirements.[5]

PGE shares Staff and OSSIA's sense of urgency regarding action that is required both to comply with HB 2021 and further portfolio decarbonization more generally. PGE believes that the procurement volumes contemplated in the 2019 IRP Action Plan and proposed in this RFP would make important progress toward meeting PGE's Green House Gas (GHG) compliance need. However, PGE recognizes that HB 2021 has underscored the importance of successfully achieving the procurement objectives identified in the 2019 IRP Action Plan. To that end, PGE will discuss further in these comments how it intends to implement the specific language of the 2019 IRP Action Plan and provide the Company with an opportunity to advance progress toward Oregon's 2030 GHG reduction targets.

Staff also posed several questions about the connection between PGE's resource procurement and the newly established carbon reduction targets mandated by HB 2021. Staff's questions are listed below along with PGE's responses.

How far off is PGE from achieving emissions reduction targets?

Using forecasts of PGE's baseline portfolio, load, and supply-side options from the 2019 IRP Update and absent any action towards HB 2021 and PGE's corporate emission reduction goals, PGE was forecasted in the Reference Case

---

[1] Staff Comments on Scoring and Modeling Methodology at 5.
[2] *Id.*
[3] *Id.*
[4] OSSIA Comments on PGE's Draft RFP Scoring and Modeling at 1.
[5] *Id.* at 2.

of the Preferred Portfolio in the 2019 IRP Update to emit 4.32 MMtCO2 in 2030.[6] To meet the Company's emission reduction goals and the targets established in HB 2021, PGE must emit at most 1.65 MMtCO2e in 2030, requiring a reduction of at least 2.67 MtCO2 from this forecast as well as the required additional non-carbon GHG emissions.

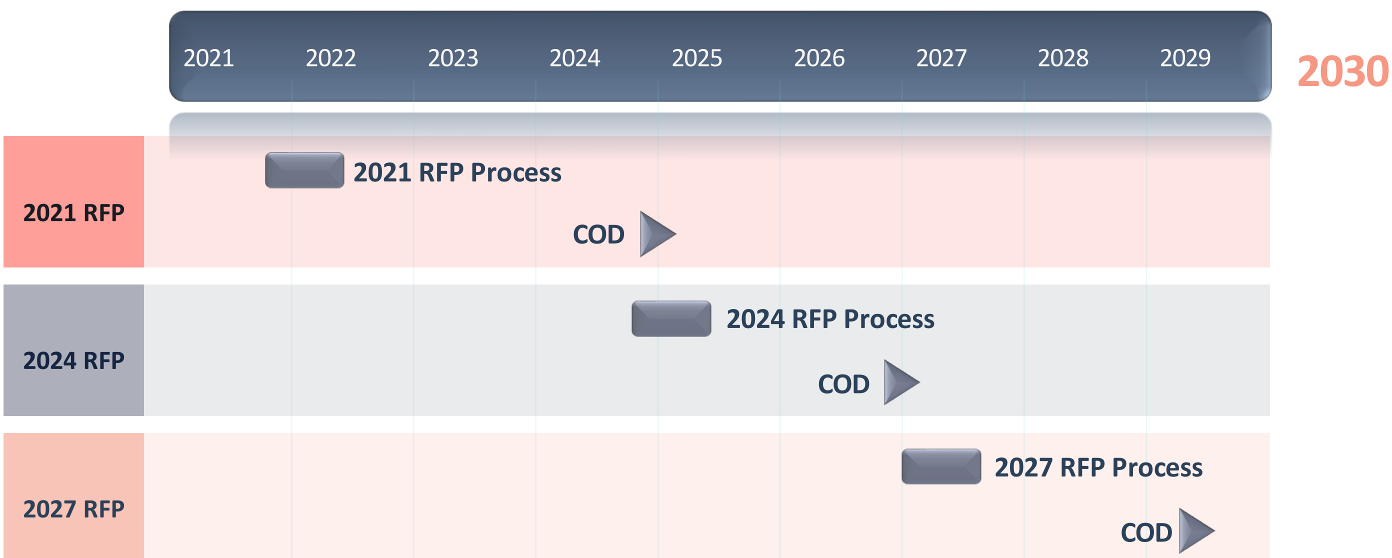
> *Can PGE provide an estimate of the MW and MWa need to achieve the targets in HB 2021 and describe how that information could be used to inform the scoring and modeling approaches?*

Initial analysis based on 2019 IRP Update load forecast and supply-side assumptions suggest that a cumulative of at least 650 MWa of renewable resources and at least 800 MW dispatchable capacity will be needed by 2030 to reduce PGE's CO2 emissions by 80%. These specific system requirements will likely change as IRP inputs and analyses are refreshed. Resources procured through this solicitation—including the 150 MWa of renewable resources, the 100 MW of Green Future Impact (GFI) resources, and the dispatchable capacity resources—will contribute toward meeting these estimated energy and capacity requirements. Discussions of scoring and methodological approaches are included below.

> *How many RFPs does PGE envision conducting prior to 2030 and when would the associated resources be expected to come online for each RFP?*

Including this RFP, PGE anticipates the opportunity to complete at least three solicitations prior to 2030. It will be necessary for all incremental renewable resources to be online prior to the close of the 2030 HB 2021 compliance year to make contributions toward meeting the policy target. Figure 1 provides an illustrative example of how three IRP driven RFP processes could fall within the next decade.

Figure 1: Feasible Procurement Pathway Timeline



[6] PGE's forecast of 4.32 MMtCO2 in 2030 includes all preferred portfolio activities including 2030 Renewable Portfolio Standard (RPS) compliance consistent with the 2019 IRP Update methodology. In the 2019 IRP Update only carbon emissions were calculated: other heat-trapping gas emissions from generation facilities are not included in this total. PGE notes that HB 2021 makes Oregon Department of Environmental Quality (DEQ) responsible for determining PGE's historic emission baseline and PGE's emissions compliance goal. PGE provides these early estimates for reference purposes only.

Is an adjustment to the energy cap needed to allow for additional procurement in this RFP to support achieving the targets for HB 2021?

Should PGE acquire 150 MWa of renewable resources for cost-of-service customers and an additional 100 MW for the GFI program, PGE will have procured approximately 25% of the currently forecasted non-emitting energy additions necessary to comply with the 2030 compliance requirement. PGE expects to engage at least two additional structured procurements prior to the 2030 compliance requirement following the 2021 All-Source RFP. As such, forecasts suggest a feasible path toward 2030 compliance, following a successful procurement of planned COS and GFI renewable volumes in this solicitation. However, it remains possible that offers received in this solicitation will provide for opportunities to make additional progress toward HB 2021 compliance and lower forecasted cost and risks for customers.

PGE's past two IRPs utilized a glide path framework to denote the optimal timing of renewable acquisitions to meet the RPS goals. How has HB 2021 impacted this approach and will an updated glide path be reflected in the modeling and scoring?

PGE continues to expect glidepath analysis to be included in future IRP filings and HB 2021 compliance plan filings. The questions regarding the optimal size and timing of required additions are core to PGE's planning activities and processes. However, those processes reflect substantial, long-leading analysis in addition to robust public process. PGE is not positioned in this proceeding to reestablish these IRP methodologies. However, PGE maintains that the methods developed in the 2019 IRP and incorporated in this RFP design are robust to PGE's new policy environment. As proposed, PGE will evaluate all resources and, through portfolio analysis, evaluate how the top performing bids are likely to provide the best combination of cost and value to PGE customers. In recognition of Oregon's current law, all portfolios will add resources necessary between now and 2030 to achieve the required 80% reduction of GHG emissions. Resource additions will include both bids received in this solicitation, and generic resources necessary to achieve the compliance target in 2030. As demonstrated in the 2019 IRP, this framework will identify a feasible path to HB 2021 compliance and recognize the cost and risk benefits associated with near term renewable additions necessary to reach future compliance obligations.

To what extent will the modeling identify any optionality benefits from the acquisition of dispatchable, GHG-free generation, especially in terms of timing? How could such an optionality benefit be captured in the scoring?

PGE's portfolio model ROSE-E incorporates optionality into analysis by considering the least-cost resource addition pathway across 810 futures. The benefit associated with optionality from a non-emitting dispatchable resource varies depending on the need, price, and technology cost future that materializes. ROSE-E captures this optionality with its risk metric, which evaluates the distribution of the cost among each of these futures.

Are PGE's scoring criteria appropriate to facilitate this RFP's contribution to achieving the HB 2021 targets (e.g. greenhouse gas emissions reductions are not included in the non-scoring criteria)?

PGE's scoring criteria are well-suited to identify those resources which provide the best combination of cost and value to PGE customers. All resources eligible for participation in the solicitation must be non-emitting resources. As such, each MWh delivered from any of the candidate resources are expected to have analogous impacts on PGE's portfolio emissions and are expected to do so until such a time in which PGE's portfolio is facing significantly increased economic curtailment due to possible oversupply conditions. For this reason, PGE does not find it necessary to introduce additional non-price scoring or screening elements related to GHG displacement as Staff questioned.[7]

> *Could elements of the cost containment screen such as the flexibility value be updated to reflect the radically different energy and capacity needs of PGE beginning in 2030 due to HB 2021?*

The cost containment screen is an element of the 2019 Action Plan that was particular to the planning environment prior to HB 2021. As is discussed in the 2019 IRP, PGE conditioned its Action Item 2 so that only resources that passed a cost-containment screen would be procured.

PGE planned and initiated its renewable procurement action before the passage and effective date of HB 2021. As such, PGE maintains that this procurement is not driven by HB 2021, but pre-existing portfolio economic findings. Should PGE find renewable resources that pass the cost-containment screen, PGE will prioritize the procurement of those highest value resources for cost-of-service customers. Should PGE procure up to approximately 150 MWa renewable resources that pass the cost containment screen, all those resources could justifiably be characterized as satisfying Action Plans acknowledged prior to the passage or effective date of HB 2021. For this reason, the costs of such a procurement should not factor into PGE's future HB 2021 cost cap calculations. If less than 150 MWa of renewable resources pass the cost containment screen, PGE will need to continue to evaluate the appropriate procurement action given the emergence of the GHG compliance requirements detailed above. In such a scenario, renewable procurement made without passing the cost-containment screen could appropriately be characterized as driven from the HB 2021 policy mandate and appropriate for consideration in future HB 2021 cost cap calculations.

> *How is PGE planning to maximize this RFP to achieve the HB 2021 targets?*

PGE currently intends to procure approximately 150 MWa of renewable resources through this solicitation in addition to 100 MW of renewable resources for GFI customers and non-emitting capacity resources necessary to meet PGE's 2025 capacity needs. This planned activity aligns with the 2019 IRP Action Plan and will place PGE on a feasible path to HB 2021 compliance. However, PGE will continue to evaluate its planned action up until making an irrevocable commitment. PGE will necessarily evaluate all bids that are received in this solicitation, and should PGE receive renewable offers of compelling value to customers, that reduce cost and risks associated with HB 2021, PGE will consider procuring volumes in excess of approximately 150 MWa. Should favorable procurement conditions arise, PGE expects to substantiate that evidence in its final short-list acknowledgement filing prior to making procurement commitments.

Advancing the 2021 All-Source RFP and successfully procuring new renewable resources and non-emitting dispatchable capacity resources on schedule is one of the most important near-term actions that PGE can make to allow for timely HB 2021 compliance. For this reason, PGE underscores the importance of avoiding procedural delay that would be associated with efforts to reassess fundamental planning methods and findings. As discussed above, the methodologies and specific Action Plan activities remain appropriate in Oregon's current policy environment. In addition, should conditions arise that create opportunity for PGE to reduce long-term costs and risks, established portfolio methodologies adjusted for current policy requirements will enable PGE to consider and evaluate procurement scenarios that may exceed proposed action plan procurement targets.

---

[7] Staff Comments on Scoring and Modeling Methodology at 6.

OSSIA notes the urgency faced in meeting GHG compliance requirements; however, PGE does not believe that the RFP docket is the appropriate forum to reperform long-term planning analysis. For this reason, it is not reasonable for PGE to include a formal HB 2021 compliance plan in this proceeding. Such analysis will require investment of considerable time and resources from PGE and its public stakeholder group which cannot be reasonably incorporated into this proceeding without significant delay. PGE looks forward to engaging in formal HB 2021 compliance plan filing with its stakeholder group but maintains that reliance on previous planned actions and IRP methodologies is appropriate.

B. Resource Adequacy

Comments from Staff also highlight the connection between the timing of this solicitation and emerging resource adequacy (RA) compliance frameworks in development in the Pacific Northwest.[8] PGE remains active in the development of the Northwest Power Pool's (NWPP) Western Resource Adequacy Program (WRAP) and remains committed to furthering its progress. While details and timing of the WRAP remain in flux, PGE believes there is alignment between the expected program initiation and the 2021 All-Source RFP.

PGE and other participants expect to receive compliance metrics (forward capacity obligation) and resource accreditation information for the winter 2022-2023 and 2023-2024 season in Q2 of 2022 and summer 2023 and 2024 in Q4 2022. This timing should align and provide additional confidence to PGE prior to finalizing the Company's resource action decisions.

The dates of the first binding and fully operational season have not been finalized but it is tentatively scheduled to be Summer of 2024. Should the NWPP successfully move forward with program implementation, NWPP expects to implement certain non-binding and non-operational RA showing periods prior to 2024. Except for long-lead-time resources, projects procured through this solicitation should be online to contribute toward some, if not all, of the RA compliance showings required seven months prior to the compliance season.

Should PGE move forward with a long-lead-time resource as a result of this solicitation which does not reach commercial online date prior to 2025, PGE would need to take additional action to meet its 2025 capacity need and possible additional action to meet emerging RA compliance requirements in 2024. Following a successful rollout of the WRAP, PGE's effort to meet its capacity needs prior to new resource online dates may be aided through bilateral capacity transactions facilitated by the regional RA resource pool for which the WRAP is designed to create additional visibility and access. Staff correctly notes that any short-term capacity transaction secured to satisfy needs prior to new resource online dates will incur an additional cost.[9]

III. PGE Needs Assessment Update

In accordance with Order No. 20-152, PGE provided updated needs assessments within the 2019 IRP Update. That update included the latest available econometric load forecast at that time, sensitivities for recent GFI procurements, market capacity information, and Qualifying Facilities (QF) assumptions.

In Order No. 20-152, the Commission also outlined its expectation that PGE provide a formal needs assessment within the IE Selection docket. PGE is supplying this update within its reply comments. This update includes the executed contract with the Confederated Tribes of Warm Springs, latest load forecast, all signed agreements for GFI, and several

[8] *Id.*
[9] *Id.* at 10.

sensitivities around QF procurements using information from the latest QF snapshot. PGE is not including sensitivities for GFI at this time as it is looking to procure only for the PGE supply option through this solicitation and has not received a request to procure or execute Power Purchase Agreements (PPA) for the Customer Supply Option.

A. Capacity Need Update

Table 1 below identifies PGE's updated capacity needs in 2025. With the updates outlined above, PGE's reference case forecasted capacity need decreased to 372 MW. There remains a wide range of uncertainty in these values, reflected in the capacity need associated with the high and low need futures.[10]

Table 1: PGE's Forecasted 2025 Capacity Need Across Need Futures (MW)[11]

	2019 IRP Update	RFP Update
High	737	587
Reference	511	372
Low	292	160

Consistent with the 2019 IRP Action Plan, PGE will procure resources to address this recently updated 2025 capacity need forecast. PGE intends to procure sufficient renewable resources and dispatchable capacity resources necessary to meet the identified 372 MW capacity contribution need. In addition, the high and low need futures will be studied within portfolio analysis to consider any economic benefits or risks associated with procuring either more or less resources, recognizing remaining forecast uncertainty regarding PGE 2025 capacity needs.

B. Energy Position Update

For these Reply Comments PGE has also updated its energy position, both of which are displayed below in Table 2. PGE's energy position is calculated as the difference in MWa between the total PGE is forecasted to purchase and sell from the market; positive values indicate PGE is a net purchaser from the market.

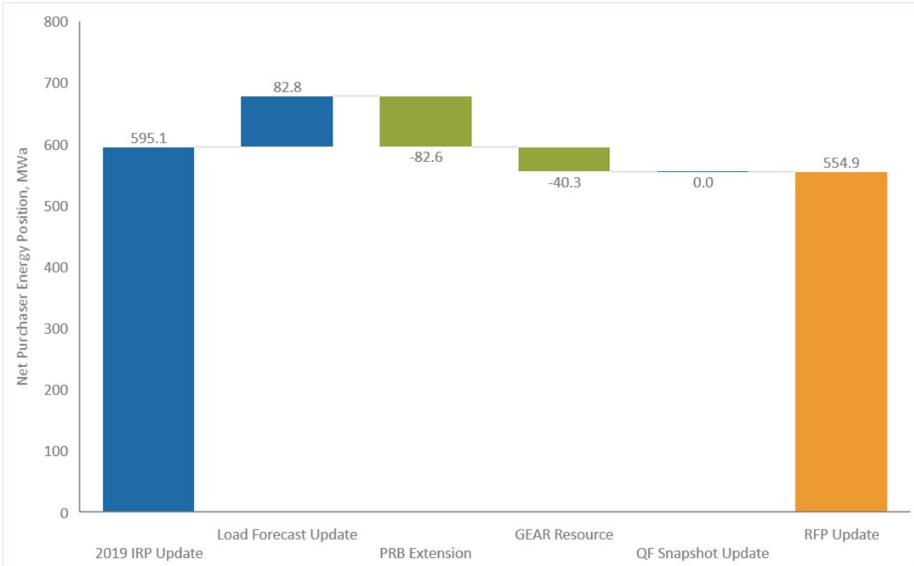
Table 2: PGE's Forecasted 2025 Energy Position (MWa)

	2019 IRP Update	RFP Update
Reference Case	595	555
10th Percentile	428	414
90th Percentile	887	825

The inclusion of an extension of PGE's purchase of 100% of the output from the Pelton and Round Butte Project and the second resource from Phase 1 of the Green Energy Affinity Rider (GEAR) surpassed the increased load forecast, leading to the reduced net market purchaser position.[12] The refreshed QF snapshot showed offsetting changes, resulting in negligible movement in the net market position. The magnitudes of these changes are displayed below in Figure 2.

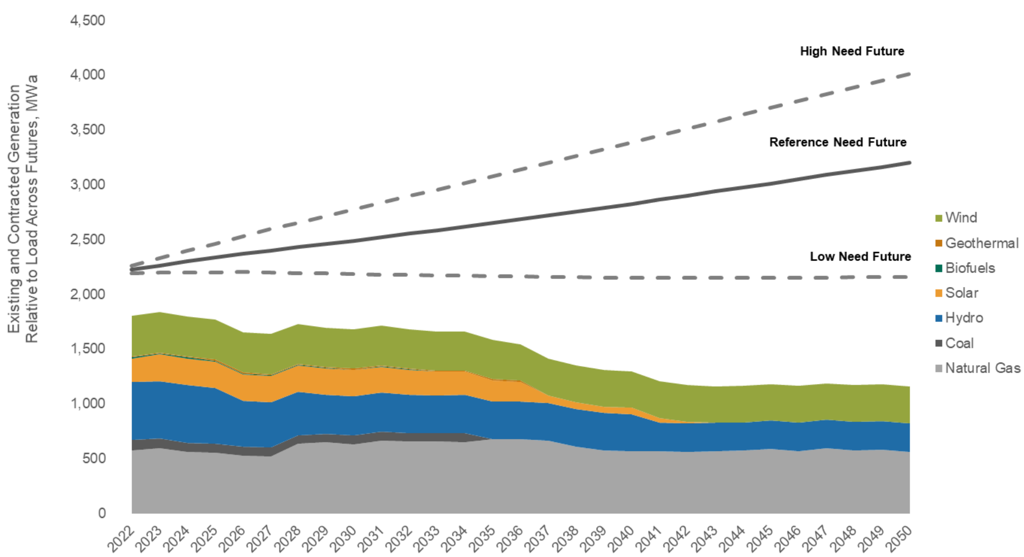
[10] *See* LC 73, PGE's 2019 IRP Table 3-1 at 73 for the construction of need futures.
[11] On August 2, 2021,PGE filed an update to the UM 1953 Green Tariff filing that evaluated capacity needs and energy position with an additional GEAR resource. Those forecasted 2025 values (Energy Position: 472, Capacity Need: 275) were not calculated with the updated load forecast used in this update.
[12] This resource is modeled as 138 MW of solar with the same characteristics as the GEAR Phase 1 first resource.

Figure 2: Changes to PGE's Reference Case Net Market Position



PGE's net market position is calculated by the difference between forecasted load and the expected contribution of PGE's baseline portfolio (all owned and contracted resources). While hydro and renewable resources are expected to contribute based on average capacity factors, existing thermal resources are economically dispatched against forecasted market prices. In this forecast, PGE used price forecasts from the 2019 IRP Update. The forecasted net market position through 2050 is displayed below in Figure 3.

Figure 3: PGE's Forecasted Energy Load Resource Balance



C. QF Sensitivities

In the 2019 IRP docket (LC 73), PGE agreed to conduct sensitivities about the contribution of QF resources.[13] The QF sensitivities presented below are based on the same methodology as the 2019 IRP and 2019 IRP Update, but reflect a June 2021 snapshot.[14]

Table 3: Forecasted 2025 Capacity Need QF Sensitivities

	Reference	High QF	Low QF
2025 Capacity Need	372	361	383
2025 Energy Position	555	521	588

IV. RFP Design Recommendations

A. Useful Points of Clarification

Comments received from Stakeholders and bidders called for clarification of select RFP design elements. PGE appreciates the opportunity to provide clarification on these points and finds that for items enumerated below there appears to be alignment with suggestions received and PGE's RFP design. PGE has grouped its response to these points of clarification and agreement into six categories: 1) Bid Eligibility Requirements, 2) Economic Analysis, 3) Commercial Operations Date, 4) Commercial Agreements, 5) Transmission and Interconnection, and 6) Green Future Impact.

1. Bid Eligibility Requirements

Labor Requirements

NIPPC requests clarification of PGE's requirements regarding the use of union labor.[15] In section 6.2 of its proposal, PGE specifies that union labor must be utilized for all major construction activities resulting from this solicitation. PGE requires that executed Engineering, Procurement and Construction Agreements include a Project Labor Agreement (PLA). PGE asks that bidders recognize this requirement upon bidding and affirm their commitment to meet the requirement and related provisions in Oregon law resulting from HB 2021. However, PGE does not expect a bidder to have secured a PLA prior to contract execution with PGE as it is customary to negotiate such labor agreements closer to construction activities.

Power Sale Requirements

NIPPC requests clarification regarding PGE's requirement that counterparties be authorized to sell power under existing law and regulation.[16] Bidders need not demonstrate authority to sell power at time of bidding. However,

[13] Order No. 20-152 at 13.
[14] *See* LC 73, PGE's 2019 IRP at 120, Section 4.7.1 – QF Sensitivities.
[15] NIPPC's Comments at 24.
[16] *Id.* at 29.

should the bidder or identified operating partner not possess authorization to sell power, prior to executing a contract, PGE will require the bidder to identify a reasonable plan to achieve this authority.

Permitting

Bidders' comments called on PGE to clarify or consider changes to PGE's RFP permitting requirements.[17] Bidders identified circumstances in which permit receipt or environmental study review could not reasonably be completed prior to offering bids with assumed 2024 commercial operation dates (CODs).[18] PGE agrees that certain required permit studies may not be finalized prior to bidding into the solicitation. PGE will modify its eagle survey requirements to allow for preliminary survey and eagle take estimates. PGE will also modify its Federal Communication Commission permits to allow bidders to acquire necessary permits prior to project construction. In addition, PGE clarifies that other Endangered Species Act or local sensitive species surveys need not include any final pre-construction follow-up studies (such as might be required for site certificate or project authorization, for the purpose of micro-siting and defining habitat boundaries in a given construction year). Instead, at the time of bid, bidders must provide comprehensive project-wide survey results for sensitive species.

PGE will continue to require bidders to furnish state and local siting permits prior to placement on the final shortlist. This timing is necessary as to allow PGE to evaluate the project's full scope and to understand all conditions imposed by the authorizing agency. In the instance where a permit has been awarded multiple years in advance of construction, PGE clarifies its intention to assume that the permit may be extended if necessary.

Site Control Requirements

Questions received from bidders call for clarification of PGE's site control requirements.[19] PGE affirms that bidders must demonstrate site control for at least 80% of the project site inclusive of all property necessary to construct the facility and meet any land use permit requirements. PGE recognizes that permits may call for specific mitigation measures that necessitate larger project footprints. Should property requirements change unexpectedly following receipt of permit, PGE expects to provide an opportunity to cure any site control deficiency prior to contracting. However, as a general matter PGE expects bidders to anticipate the property requirements necessary to satisfy expected permit requirements.

Financing and Credit Requirements

Staff's comments request additional explanation and clarification of PGE's financing and credit requirements.[20] Staff suggests additional discussion as to what would constitute a reasonable plan to obtain project financing and ,in addition, requests explanation of minimum credit requirements for non-investment grade bidders.[21] NIPPC's requests additional discussion and detail regarding the documentation to substantiate a good faith commitment from a financial institution or lender and asks PGE to consider allowing bidders to meet credit requirements through bonding as opposed to letter of credits.[22]

---

[17] Summary of Bidder Questions and Comments at 4.
[18] *Id.*
[19] *Id.* at 2.
[20] Staff Comments on Scoring and Modeling Methodology at 12.
[21] *Id.*
[22] NIPPC's Comments at 23.

When evaluating bidders who possess the balance sheet necessary to finance construction activities, PGE must identify and develop confidence in a bidder's ability to partner with a financial partner to deliver on the proposed bid providing value to PGE's customers. A reasonable plan should demonstrate a straightforward and achievable path to successfully receive project financing from a financial partner. This plan should identify the financial institution(s) for which the bidder plans to do business with and to enumerate the history of business with this lender. Should the bidder not be investment grade, PGE will require the bidder to partner with investment grade counterparty. For third-party built utility owned structures, non-investment grade bidders will be required to receive a parental guarantee from an investment grade counterparty in addition to receiving a letter of credit from a qualified financial institution and eventually posting a payment and performance bond. For third-party owned structures, non-investment grade bidders will be required to receive a letter of credit. Prior to placement on the final shortlist all non-investment grade bidders will be required to furnish documentation of the ability to secure a parental guarantee or letter of credit in a form consistent with the Guaranty Commitment Letter and Letter of Credit Commitment Letter shared in Appendix E of PGE's 2018 Renewable RFP.[23]

PGE's competitive solicitation experience has reinforced the importance of the above-referenced credit and financing requirements, particularly for non-investment grade bidders. Competitive bidding typically promotes favorable customer outcomes when numerous bidders of diverse backgrounds and composition participate. However, prior to entering the advanced stages of the solicitation, it is imperative for the buyer to have confidence that all remaining bidders are capable of delivering their offer without transferring undue risk onto PGE and its customers. PGE simply cannot enter into high gross value contracts without assurances regarding the creditworthiness of the counterparty. PGE maintains that the aforementioned commitment letters are a simple and achievable mechanism to evidence a bidder's ability to secure these necessary credit protections for PGE.

2. Economic Analysis

<u>Energy and Capacity Value</u>

NIPPC provided select comments and suggestions regarding PGE's proposed economic analysis. The comments received provide several opportunities for useful clarifications.

NIPPC questioned whether energy values would be determined by the bidder or by PGE, particularly for storage resources.[24] NIPPC suggests that PGE model the dispatch of energy storage resources to forecast bids' energy values.[25] PGE confirms that PGE will calculate the energy value for all resource types and will explicitly model the forecasted dispatch of energy storage resources and hybrid renewable plus storage resources.

PGE offers additional clarifications to partially resolve some of NIPPC's concerns regarding the estimation of capacity value. NIPPC references some disagreements expressed in PGE's 2019 IRP Update process regarding the inputs used in PGE's capacity adequacy model.[26] The concerns regarding the suggested lack of geo-specific solar locations should not generally apply in this RFP setting, as PGE will explicitly model the specific project forecasted output associated with each bid rather than relying on proxy wind or solar profiles. PGE developed and incorporated its capacity model

---

[23] *See* UM 1934, Portland General Electric Company's 2018 Request for Proposals for Renewable Resources at 5. https://edocs.puc.state.or.us/efdocs/HAH/um1934hah163417.pdf
[24] NIPPC's Comments at 29.
[25] *Id.*
[26] *Id.* at 19.

Sequoia in the 2019 IRP Update. In particular, the challenges and complexities associated with estimating the capacity performance of energy limited resources like energy storage demand a sophisticated model that allows PGE to dispatch the energy storage resource in time of highest need.

Lastly, as described in its application, PGE will assess capacity value throughout the solicitation using both the generic capacity costs included in the 2019 IRP Update and the specific costs for the non-emitting dispatchable resources. Following receipt of all dispatchable capacity bids and performing cost and performance analysis, PGE will identify the levelized cost per unit capacity for all bids. PGE intends to identify the statistically relevant representative capacity cost for these resources. If PGE receives many dispatchable capacity bids with widely distributed costs, PGE would identify the 25th percentile as the representative cost of new, non-emitting capacity. With fewer bids received it may be appropriate to instead rely upon an average or median as the representative cost. In either case, PGE will use both the representative bid cost of capacity and generic cost of capacity as sensitivities when evaluating the cost and performance of each individual bid and then again when assessing the portfolio economics of assembled portfolios.

Term Length Evaluations

NIPPC requests additional clarification regarding how resources of different term length will be compared in this solicitation.[27] As has been customary in PGE's RFP processes, PGE will initially evaluate all bids on an individual basis to determine the resource's economic performance and resulting price score. When performing the individual offer analysis, each bid's cost and value will be forecasted, discounted on a present value basis, and then associated with a forecasted real-levelized cost and value. Once each bid's real-levelized cost and value are calculated, all bids will be compared directly against each other without further adjustments to account for project term length. An additional methodology is used to evaluate resources that are included in PGE's shortlist and included in portfolio analysis. In portfolio analysis, each bid is included in a number of portfolios which include the forecasted cost and value associated for each bid for the years the resource is online. Each portfolio is constructed to meet a common capacity adequacy standard and non-emitting energy volume necessary to meet HB 2021 compliance obligations through the additions of generic capacity and renewable energy resources with associated forecasted real-levelized cost and value. Should bid term lengths differ across portfolios, greater or fewer generic resources will be added to term and volume normalize each portfolio. Following the described portfolio construction, portfolios may be compared against each other to identify those combinations of offers that present the best combination of cost and risk for PGE's customers.

Questions received by bidders seek additional clarity regarding the assumed term length for energy storage assets.[28] Currently PGE depreciates battery storage assets over 15 years based on depreciation parameters approved in the current depreciation study. Depreciation studies are performed at least every five years and include input from an outside depreciation consultant. The appropriate depreciation parameters for any asset acquired by PGE would be evaluated through the depreciation study process, which is inclusive of assumptions of changes in technology, company policies and practices, and other industry trends. We continue to believe that an O&M contract that guarantees a useful life of the facility should be a critical factor in establishing the depreciation period of the asset upon acquisition. Should a long-term O&M contract exceed PGE's assumed depreciable life for energy storage or another technology, PGE will consider matching its assumed economic life to the term of the commercial guarantee associated with the O&M contract.

---

[27] *Id.* at 25.
[28] Summary of Bidder Questions and Comments at 2.

3. Commercial Operations Date

Risk Associated With Long-Lead Time Resources

Staff's comments appear supportive of PGE's proposed RFP design to allow for pumped storage resources with as late as December 31, 2027.[29] Indeed, PGE's proposed RFP COD requirements are designed to meet commitments made in the 2019 IRP process to make reasonable accommodations to allow long-lead time resources such as pumped storage to participate in PGE's competitive solicitation.[30] Staff speculates that PGE could likely meet approaching capacity needs through alternative means while waiting for pumped storage resources to reach COD. However, Staff requests additional clarification on the risks that PGE might face in such a circumstance and what conditions may prompt PGE to reconsider a procurement solution that depends on late-dated CODs.[31]

PGE continues to support an RFP design that would allow for participation from pumped storage resources that require a long-lead time construction cycle. However, it is important to remain clear regarding the risk associated with this approach and to maintain flexibility should conditions warrant a change. PGE faces a meaningful capacity deficit in 2025 that is forecasted to grow throughout the decade due to load growth, changing weather, and expiring bilateral contracts. To rely on wholesale market activities or replacement short-term contracting to allow for long-lead time construction cycles would impose real reliability and economic risks. Should PGE be unable to cover its capacity deficit on a forward basis due to an inability to secure capacity, PGE and its customers will be exposed to possible market liquidity events triggering extreme price environments and possible energy shortages with direct reliability consequences.

A separate risk for long-lead time resources relate to increased construction forecast risk. Generally, the project timeline that depends upon six years of construction activities to support a 2027 COD includes more schedule uncertainty than a project timeline requiring only twelve months of construction to support a 2023 COD. While PGE may be able to commercially limit some of the economic risks associated with long-lead time construction delays through contract provisions including delay damages, PGE would face elevated economic and reliability consequences that were not forecast in the RFP evaluation.

Should PGE find pumped storage resources to provide strong cost and risk benefits for PGE's customers, PGE will evaluate the feasibility of mitigating its capacity shortfall risks prior to committing to a supply plan that relies upon the successful completion of a long-lead time resources. These feasibility studies will likely include, but not be limited to, assessing the market liquidity for forward purchases, a study of the current resource adequacy program implementation progress, availability of mid-term, specified-source transactions, and regional capacity fundamentals analysis.

Staff also questions why PGE's RFP design might limit long-lead time resources to only pumped storage technologies.[32] It is important to PGE to limit 2027 COD allowances to only those technologies which have a long construction cycle and therefore require a late dated COD even for a project whose development process is mature. PGE does not support extending 2027 COD allowance to technologies that do not require long-construction cycles, or to projects that are relatively early in their development, or to technologies that require additional time to reach

[29] Staff Comments on Scoring and Modeling Methodology at 9.
[30] LC 73, PGE's 2019 IRP Final Comments at 9.
[31] Staff Comments on Scoring and Modeling Methodology at 9.
[32] *Id.* at 9.

commercialization. Staff's comments appear to support this position, however, PGE agrees with Staff's suggestion and clarifies that any bidder is welcome to participate in the solicitation even if the bidder cannot meet PGE's minimum requirements. While PGE will not procure a resource that does not meet RFP requirements, PGE values participation from less developed, or non-commercialized bids for the reasons identified by Staff—information shared by bidders allows PGE to identify opportunities that may be available to customers in future procurements or pilot projects.[33] If there exists another technology that has met PGE's commercially proven technology requirement that also require a long construction cycle, PGE would consider allowing for those resources to qualify for a COD no later than December 31 2027, provided that the bid meets all other RFP eligibility requirements.

<u>Non-Price Scoring</u>

Staff and bidders provided specific recommendations regarding PGE's proposed non-price scoring rubric relating to CODs for dispatchable resources. Both Staff and bidders note an unintentional oversight in PGE's non-price scoring rubric related to the non-price score for project CODs in 2025.[34,35] Staff expresses some concern regarding the ability of long-lead time resources to compete in the solicitation given the proposed non-price scoring treatment and questions whether a long-lead time resource would be penalized in both non-price scoring and portfolio analysis.[36] Bidders suggest that PGE consider providing full non-price score points for bidders reaching a COD by the end of 2024 given development and supply chain difficulties associated with reaching an earlier COD.[37]

PGE clarifies that PGE's proposed RFP design does not double penalize long-lead time resources in non-price scoring and portfolio analysis. PGE's proposed portfolio analysis will term and volume normalize all portfolios which does not act as a penalty, rather is a necessary technique allowing for comparison of portfolios on a comparable basis. PGE regrets the oversight in Table 7 of PGE's Scoring and Methodology Proposal which should have associated CODs after 12/31/2024 with zero points. PGE is open to considering proposed adjustments to this non-price scoring rubric; however, it remains important to retain a meaningful non-price consequence for a late COD. Given the regional capacity shortfalls, impending resource adequacy compliance obligations, and the risks associated with late-dated CODs, projects with long-lead times must demonstrate significantly improved price score benefits to justify their consideration. When evaluating two resources—one with a 2024 COD and another with a 2027 COD—with roughly comparable levelized economic performance, PGE should prioritize the selection of the 2024 COD resource given the significantly reduced risk associated with that proposal. This preference is incorporated into PGE's non-price scoring design and is an important principle to retain.

---

[33] *Id.*
[34] *Id.*
[35] Summary of Bidder Questions and Comments at 5.
[36] Staff Comments on Scoring and Modeling Methodology at 10.
[37] Summary of Bidder Questions and Comments at 5.

4. Transmission and Interconnection

Requirements

PGE received several questions and comments from stakeholder and bidders regarding the application of PGE's transmission requirements. In this section PGE addresses those issues that appear to be resolved through simple clarification.

As detailed in PGE's Scoring and Methodology Proposal, all bidders are required to meet PGE's identified transmission requirements. For renewable and dispatchable resources, bidders are required to provide a reasonable and achievable plan to obtain required volumes of long-term transmission service prior to the project COD.[38] Renewable resources relying on BPA for transmission service are required to have previously granted eligible transmission service or an eligible and active Transmission Service Request participating in BPA's transmission study process. Resources interconnecting within PGE's system must demonstrate an achievable plan to rely on network transmission service by requesting network resource interconnection service from PGE and committing to fund identified network upgrades, if any.

PGE's RFP design will comply with the Commission's Competitive Bidding Rules regarding the availability of bid elements owned and controlled by the Company and relied upon for a Benchmark resource. Should the Benchmark bid rely upon transmission rights controlled by PGE, PGE will either make that bid element available to all bidders or PGE will explain why the Company elects not to make those elements available. PGE's request for RFP approval will include a discussion of those bid elements which would be available or unavailable to third party bidders.

PGE clarifies that a request for a long-term redirect of an existing transmission service request may satisfy PGE's transmission requirements. PGE would consider a long-term redirect to constitute a reasonable and achievable plan provided that BPA can grant the redirect and the bidder has clearly requested the reservation priority rights follow the redirect request.

As described in PGE's Scoring and Methodology Proposal, all off-system resources will interconnect and deliver resource output to PGE via BPA's transmission system. PGE's RFP will require and assume that off-system resources are integrated by BPA and will apply BPA's spinning and non-spinning reserve cost and integration costs reserve costs. Aside from reserves and integration costs, all other third-party balancing authority area and ancillary charges and line loss costs will be considered in the bid evaluation.

NIPPC's comments suggest PGE provide certain communications to bidders should transmission bid requirements not be met.[39] As a general matter, PGE's RFP procedures include direct communications with bidders should a bid be found to be non-compliant. In addition, bidders are typically given a brief amount of time to cure these identified deficiencies. PGE intends to adopt and perform these same RFP procedures consistent with NIPPC's recommendation.

---

[38] PGE's Request for Commission Approval to Engage IE and Application for Approval of Scoring and Methodology at 10.

[39] NIPPC's Comments at 3.

In all instances, bidders will be required to have met PGE's interconnection eligibility requirements. Staff's comments request clarification regarding the difference in language used in PGE's Scoring and Methodology Proposal and PGE's August 9th Workshop presentation.[40] The intent of the language in both documents is the same. To be an eligible bidder in PGE's solicitation a bid must include an active generation interconnection request and a completed system impact study. In the event that the interconnection involves multiple transmission providers, the bid must include requests and studies for all impacted systems. A completed facilities study must also be completed to be remain eligible for inclusion on PGE's final short-list.

Transmission Risks

Staff's comments call for additional support and discussion of PGE's transmission scoring proposal. Specifically, Staff requests a discussion of PGE's rational for proposing to have transmission product types impact multiple scoring criteria, the types of transmission risks PGE has identified, and comment on experience facing similar transmission risks.[41] NIPPC's comments question whether certain transmission products would be penalized twice and raise the suggestion that PGE reconsider some of its transmission product type non-price scoring criteria to include bridge period terms as opposed to transmission product types.[42]

As discussed in PGE's 2019 IRP and PGE's Scoring and Methodology Proposal,[43] PGE faces an increased number of significant risks when relying on short-term transmission products and/or transmission products with lower priority than firm transmission reservations, coupled with BPA's elimination of the availability of the hourly firm transmission product in the real-time operating horizon. The fundamental event concerning PGE for such transmission product types is an inability to deliver available generation to meet load due to unavailable transmission inventories. Such events place direct economic and operational uncertainties on PGE, as PGE must respond to these events by identifying replacement energy during a time period of high system utilization and decreased transmission system flexibility. Should replacement energy not be available in such time periods, due to market supply conditions or lack of transmission availability and/or transmission delivery constraints or curtailment, PGE would also face risks related to compromised electric service reliability including, emergency system conditions, WRAP penalties for failure to deliver, NERC reliability standard penalties, and ultimately emergency load curtailment.

PGE evaluates the magnitude of the transmission risks presented by each bid in several ways throughout its scoring methodology. By estimating and including a capacity value, PGE's price scoring analysis directly estimates the reduced contribution toward supporting reliability for all bids that do not secure a full volume of long-term firm rights. However, this methodological step only accounts for reduced capacity contributions from bidder and does not capture reduced energy value and the economic risk associated with transmission unavailability. PGE's energy value methodology cannot easily capture the economic risk associated with short-term firm unavailability or conditional firm curtailment because PGE energy value tools forecast average system conditions and average market prices for a given future scenario. Lack of transmission availability is expected to occur during stressed system conditions that are not forecasted in PGE's long term economic dispatch forecasts. To capture these additional economic risks posed by bidder transmission plans, PGE has proposed to rely upon non-price scoring.

[40] Staff Comments on Scoring and Modeling Methodology at 12.
[41] *Id.* at 11.
[42] NIPPC's Comments at 8.
[43] PGE's Request for Commission Approval to Engage IE and Application for Approval of Scoring and Methodology 10.

Historically, PGE has planned and managed its transmission portfolio through securing BPA's most reliable, firm transmission products and ensuring each resource had transmission rights equal to the full output of the resource to deliver to PGE's load using long-term firm transmission. Long-term firm transmission has played an important role in PGE's provision of reliable load service as it has the highest curtailment priority (least likely to be curtailed), has been available for procurement sufficiently in advance of delivery, has provided certainty as an annual product and the on-going right to renew if the contract term was five years or longer. Additionally, prior to BPA's elimination of hourly firm product in the real-time operating time horizon, PGE had access to unlimited hourly firm transmission service on BPA's transmission system, which further ensured reliable load service.

PGE's transmission requirements must continue to satisfy PGE's need to serve loads reliably, to minimize the operational cost and risks related to transmission constraints, and to be assured a certain level of deliverability of resources for which PGE's customers have made a sizable investment. The transmission landscape of the Northwest is in a dynamic state at a time when resource portfolios are shifting heavily toward renewable resources. PGE recognizes these structural shifts in the region and has actively considered such shifts in the development of the proposed RFP transmission requirements, all the while balancing reliability, cost, risk and decarbonization goals.

A separate transmission risk faced by PGE but not captured directly in PGE's scoring methodology are construction forecast risks. PGE's proposed RFP design and calendar will likely lead to resource commitments prior to the completion of BPA's administrative process to approve and fund construction project(s) necessary to allow conditional firm bridge resources to be converted to long-term firm. Should BPA delay necessary transmission upgrades, PGE will be exposed to transmission curtailment risks for a longer period of time than was forecast in the RFP process. Generally, bidders who have been offered conditional firm service with estimated long-lead time transmission upgrades plans are at increased risk of schedule slip in converting from conditional firm bridge to long-term firm. NIPPC's non-price scoring suggestion to include scoring criteria related to the length of the bridge period is useful in partially recognizing this risk factor.[44] PGE will consider this helpful recommendation.

5. Green Future Impact Solicitation

As stated in PGE's Scoring and Methodology Proposal, PGE intends to leverage this solicitation to identify and procure renewable resources to supply PGE's Green Future Impact (GFI) program. Staff raised several questions related to the integration of the intended GFI procurement with renewable procurement performed on behalf of PGE's cost of service (COS) customers. Staff's questions touched on issues relating to sharing RFP administration costs between PGE and participating customer and project selection criteria.

Under PGE's proposal, participating customers would contribute to the costs associated with RFP administration through selection of an RFP bid submitted with a required bid fee. All bidders will be required to pay PGE a bid fee to participate in the solicitation to help offset the costs of program administration. PGE's specific bid fee for the 2021 All-Source RFP will be identified in the RFP approval filing. Participating GFI customers will effectively contribute toward program costs by increasing the expected procurement volume and reinforcing bidder participation that generate bid fees.

PGE's planed procurement of GFI resources will not differentiate between COS and GFI resources when scoring bids. All bidder minimum requirements, economic analyses, price and non-price methodologies will be implemented

[44] NIPPC's Comments at 7.

consistently for all bids. The only distinctions between the two procurement tracks will arise upon identification of the final shortlist. First, all resources that are to be selected for COS customers will be identified and would generally follow the rank order of the final shortlist. Selecting resources for COS customers on a priority basis will ensure preferred access to the highest value resources. Of the remaining resources not selected for procurement for COS customers, PGE will work with participating customers to identify the best resources to meet the GFI program need. PGE expects that the GFI resource selection will also follow the rank order of remaining projects on the final shortlist. However, PGE will conduct direct outreach with participating GFI customers to identify whether specific technology, location, or resource volume considerations would justify procurement of secondary resources recognizing the participating customer would be required to make elevated payments to cover the additional costs to source a preferred resource type.

6. Commercial Agreements

Comments received by NIPPC include substantive and useful suggestions regarding PGE's proposed methodology to account for commercial risks associated with all bids. NIPPC makes a specific recommendation to allow for energy storage resources to contract with PGE under a tolling agreement.[45] In addition, NIPPC suggests that PGE's scoring methodology is overly weighted toward an assessment of commercial risk presented in each bid through proposed redlines to PGE's form term sheets.[46] NIPPC requests that parties keep an open mind on this scoring element until parties have had an additional opportunity to review PGE's form term sheets.[47]

PGE also recognizes the value of a tolling agreement when contracting for energy storage and will include a form agreement in its solicitation that reflects the general structure of a classic tolling agreement. In a tolling agreement, PGE will control the timing and delivery of charging energy. Through this structure PGE should be well-positioned to manage the interconnection and grid impact risks flagged by Staff's comments.[48]

PGE also agrees that discussions with stakeholders regarding PGE's assessment of a bid's commercial risk will be much enhanced following PGE's publication of its draft form term sheets and form agreements. As a point of process clarification, PGE believes that the Scoring and Methodology review associated with the Commission's Competitive Bidding Requirements (CBRs) do not include a review of PGE's proposed form agreements. PGE will include these documents in PGE's RFP Approval application and looks forward to further discussions with Stakeholder regarding the risk allocation proposals contained in those form agreements.

B. Identified Differences of Opinion

Some comments received by stakeholders recommend changes to PGE's proposed RFP design that PGE does not support as they would not further desired customer outcomes. In this section of PGE's Reply Comments PGE identifies substantiative disagreements with select stakeholder comments that suggest a difference in philosophy unlikely to resolved through simple clarification. These areas of disagreement are grouped into three sections:

---

[45] *Id.* at 26.
[46] *Id.* at 14.
[47] *Id.*
[48] Staff Comments on Scoring and Modeling Methodology at 11.

1) Minimum Bidding Requirements, 2) Transmission, 3) Competitive Bidding Rule Requirements, 4) Price & Non-Price Weightings, and 5) Locational Preferences.

1. Minimum Bidding Requirements

In comments, NIPPC makes three specific and substantial recommendations to change PGE's minimum bidding requirements. NIPPC proposes that all renewable resources be allowed to bid a COD of December 31, 2027 as opposed to just eligible long-lead time resources,[49] that existing resources be allowed to participate in the solicitation as opposed to only new resources,[50] and that hybrid renewable plus storage resource be treated as non-emitting dispatchable resources for the purpose of RFP design considerations and eligibility criteria.[51] On these points, PGE disagrees.

PGE's RFP COD exceptions for long-lead time resources should remain narrow. As identified above, PGE has pressing capacity and renewable energy resource portfolio demands. It is imperative that PGE continue to make progress toward HB 2021's 2030 compliance requirement. Delaying renewable procurement from this solicitation to as late as end of year 2027 will frustrate PGE's ability to accelerate decarbonization and would appear inconsistent with the purpose of HB 2021 and the Governor's Executive Order 20-04.[52] Furthermore, delaying renewable procurement until 2027 will increase the capacity shortfall faced in 2025, thereby placing increased economic and reliability risk on PGE and its customers as described above. PGE's commitments in the 2019 IRP process were specific in their accommodation for resources that have a demonstrated long-construction cycle and thereby necessarily require a longer COD allowance in order to participate in a competitive solicitation. This allowance does not extend to renewable projects that can reasonably achieve shorter construction timelines provided their developers have invested the necessary time to mature the development rights and assets to meet PGE's RFP requirements. Additionally, allowing extended CODs for renewable resources increases PGE's exposure to speculative bidding practices in which bidders bet that a winning bid's project costs will have fallen significantly enough to earn required investment returns—and walking away from the project should those bets not materialize.

PGE's RFP specifically targets new non-emitting resources. In the 2019 IRP Action Plan, PGE purposely pursued existing resources through bilateral transactions.[53] PGE maintains that the bilateral process has been a successful avenue to evaluate opportunities to acquire existing resources and that PGE's efforts to comply with HB 2021 could be frustrated by allowing for the procurement of existing resources. As noted above, PGE has a demonstrated need to acquire renewable resources to further decarbonize its portfolio. This mandate to decarbonize continues at rapid speed for another twenty years until 2040. Should PGE procure existing resources through this solicitation, not only would those resources not make incremental regional contributions from a decarbonization or reliability perspective, but those existing resources could likely reach the end of their useful life prior to 2040 when the need for incremental renewable energy is highest. PGE clarifies that the RFP will consider an expansion of a separate project phase at an existing facility to be a new project eligible for RFP participation.

---

[49] NIPPC's Comments at 28.
[50] *Id.* at 24.
[51] *Id.* at 22.
[52] https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf
[53] *See* LC 73, PGE's 2019 IRP Action Plan, Action 3A.

PGE disagrees that renewable resources with storage should be defined as dispatchable resources for the purpose of PGE's RFP eligibility requirements. To be considered a dispatchable resource, a project must be able to respond to PGE dispatch instructions without limitations related to available on-site generation. Hybrid resources that combine storage and a renewable resource will be considered renewable resources as the available charging energy is limited to on-site generation for at least the first five years of the asset's life. Storage resources that rely upon on-site solar generation for example are very unlikely to be capable of responding to unfettered winter season dispatch instructions due to the unavailability of solar generation in the winter necessary to fully charge the battery on a dependable basis. PGE clarifies that should a bidder place no commercial or economic limitation on hybrid renewable plus storage resource's ability to charge from sources other than on-site generation, and if facility can respond to dispatch instructions in a manner equivalent to stand alone storage resources, then PGE would consider such a resource dispatchable for the purposes of this RFP design.

2. Transmission

NIPPC proposes that PGE modify its methodology for evaluating the capacity performance of resources relying on conditional firm bridge. Specifically, NIPPC proposes that PGE assume that only 50% of BPA's available curtailment hours are curtailed. [54] NIPPC suggests that there is not significant correlation between PGE's high load hours and hours in which BPA might expect transmission congestion and that on a historical basis BPA has not engaged in significant conditional firm curtailment.[55]

PGE does not believe that NIPPC's proposed methodology changes are in PGE's customer interests. On a planning basis, PGE is relying on renewable resources delivered on lower priority transmission product to be available to support PGE's bulk system reliability. As communicated in PGE's 2019 IRP Interim Transmission Solution, such transmission products introduce additional costs and risks to customers and PGE. For this reason, the Interim Transmission Solution proposed adopting modified procurement requirements on a provisional basis and to observe over the next five years the magnitude and frequency of such events.[56] PGE agrees that BPA is unlikely to fully utilize all available curtailment hours for all years of conditional firm service. PGE also agrees that all BPA curtailment hours are unlikely to occur exactly in the hours of peak PGE demand. PGE is unable to capture all risks directly in its proposed modeling approach but has proposed and maintained conservative planning assumptions to balance against reliability consequences. PGE continues to believe that this approach is the most reasonable, given the collective new experience regional participants will gain with respect to condition firm product types and given the fact that PGE's reliability requirements and standards are not conditional in nature and must be met regardless of third-party transmission curtailment practices.

3. CBR Requirements

NIPPC's comments suggest that PGE's proposed non-price scoring methodologies do not align with the Commission's CBRs.[57] PGE disagrees. NIPPC suggests that inclusion of a non-price scoring element that relates to a minimum bidding requirement—in this case transmission product requirements—does not align with OAR 860-089-0400(2)

---

[54] NIPPC's Comments at 5.
[55] *Id.* at 4.
[56] LC 73, PGE's 2019 IRP Addendum – Interim Transmission Solution at 6.
[57] NIPPC's Comments at 5.

and (2)(c).[58] Further, NIPPC argues that PGE's proposed non-price scoring cannot reasonably be self-scored by bidders and should therefore be changed.[59]

PGE's proposed non-price scoring criteria are consistent with the Commission's CBR. NIPPC's narrow reading of the CBRs is not aligned with other language in the CBRs and if NIPPC's interpretation of the CBRs taken to its natural conclusion, customer interests would be harmed.

NIPPC argues that because PGE has created a minimum requirement for transmission product eligibility that it cannot also perform non-price scoring related to a bidders transmission product delivery plan.[60] OAR 860-089-0400(2)(c) requires that "non-price scoring criteria that seek to identify minimum thresholds for a successful bid and may readily be into minimum bidder requirements must be converted into minimum bidder requirements."[61] In this instance, PGE's proposed non-price scoring criteria distinguish those transmission plans that rely on increasingly firm transmission products, all of which have met PGE's minimum requirements. PGE's proposal does not create an effective minimum requirement through punitive non-price scoring methods; instead, it provides non-price scoring benefit to those projects that meet and exceed the identified minimum requirements and thereby reduce risk to PGE and its customers.

NIPPC argues that any non-price score that cannot be readily self-scored by bidders should not be allowed.[62] OAR 860-089-0400(2)(b) requires that "Non-price scoring criteria must be objective and reasonably subject to self-scoring analysis by bidders."[63] As PGE has proposed to partially award non-price scores based on adherence to PGE's standard form term-sheets, NIPPC argues that such application of PGE's judgement cannot be readily self-scored by bidders and therefore should not be allowed under the CBRs.[64] In PGE's view, NIPPC's interpretation conflicts with the first sentence of OAR 860-089-0400(2)(b) which directly states "Non-price scores must, when practicable, primarily relate to resource characteristics identified in the electric company's most recent acknowledged IRP Action Plan or IRP Update and *may be based on conformance to standard form contracts*."[65] (Emphasis Added) The rules should and do allow for bidder score differentiation related to a bidder's decision to modify important commercial terms that transfer risk onto PGE and its customers.

Lastly, NIPPC argues that PGE's 'Level Capacity Ratio' should not be allowed as bidders cannot calculate the ELCC of their bid which would be necessary to self-score. However, bidders can readily estimate their bid's ELCC through a simple review of PGE's 2019 IRP and 2019 IRP Update thereby allowing a bidder to reasonably estimate a self-score for PGE's non-price scoring criteria.

---

[58] *Id.* at 6.
[59] *Id.* at 13.
[60] *Id.* at 5.
[61] OAR 860-089-0400(2)(c).
[62] NIPCC's Comments at 13.
[63] OAR 860-089-0400(2)(b).
[64] NIPPC's Comments at 13.
[65] OAR 860-089-0400(2)(b).

4. Price & Non-Price Weighting

NIPPC's comments suggest that PGE should increase its weighting of PGE's proposed price score to an 80/20 price, non-price score weighting.[66]

PGE clarifies that PGE will perform multiple price and non-price sensitivity in its analysis. In the Scoring and Methodology Proposal PGE describes its intent to perform both a 70/30 and 50/50 price and non-price weighting sensitivity.[67] However PGE maintains that the relying on a 60/40 price and non-price base methodology remains appropriate. PGE believes that NIPPC's argument does not recognize the important of differentiating proposals based on the integral commercial risk related to each project. NIPPC has made similar arguments in PGE's past RFPs. These arguments, at times, have suggested that non-price scoring is less transparent, less direct, and less determinative of good customer outcomes. PGE disagrees.

PGE clarifies that a price score is not fundamentally driven by a bidder's proposed bid price—instead it is driven by the long-term forecasted bid cost and the long-term forecast bid values. For this reason, there exists considerable uncertainty, rather than transparency, embedded into a price score. In contrast, non-price scoring reflects known and certain bid differences related to risks faced by PGE (e.g., CODs, redlined or diminished availability guarantees, scheduling and forecasting challenges, or security and collateral concerns). It is important to give adequate emphasis to these important bid differentiators which protect PGE and its customers from the most extreme risks related to project failure. Due to the importance of non-price scoring, PGE has historically applied a 60/40 price, non-price weighting in all but one RFP (PGE's 1993 RFP utilized a 50/50 price, non-price weighting) since the Commission adopted its Competitive Bidding Guidelines. In Docket UM 316, Staff recommended that RFPs be required to utilize a non-price scoring weight between thirty and fifty percent.[68] The Commission adopted this requirement.[69]

5. Locational preferences

OSSIA's comments request that PGE's scoring and modeling methodology should reflect a preference for new energy facilities to be built and operated in Oregon.[70] PGE disagrees that making such an RFP design change would be in the best interest of customers and compliance with HB 2021. To successfully integrate large amounts of incremental renewable resources it will be important from a portfolio perspective to benefit from expansive renewable geographic and technology diversity. Embedding a preference for Oregon project could undermine this principle.

---

[66] NIPPC's Comments at 8.
[67] PGE's Request for Commission Approval to Engage IE and Application for Approval of Scoring and Methodology at 19.
[68] Order No. 91-1383 at 18.
[69] *Id.* at 19.
[70] OSSIA Comments on PGE's Draft RFP Scoring and Modeling at 2.

V. Conclusion

PGE appreciates the opportunity to provide these Reply Comments. PGE would like to thank Staff and stakeholders for the attention directed to PGE's RFP Scoring and Methodology Proposal and looks forward to additional discussions with those parties and the Commission.

Dated this 13th day of September, 2021.

Erin E. Apperson, OSB No. 175771
Assistant General Counsel
Portland General Electric Company
121 SW Salmon Street, 1WTC1301
Portland, Oregon 97204
(503) 464-8544 phone
(503) 464-2200 fax
erin.apperson@pgn.com