Portland General Electric Company
Legal Department
121 SW Salmon Street • Portland, Oregon 97204
503-464-7822 • Facsimile 503-464-2200

Loretta I. Mabinton
Associate General Counsel

April 13, 2018

Via Electronic Filing

Oregon Public Utility Commission
Attention: Filing Center
201 High Street, Ste. 100
PO Box 1088
Salem OR 97308-1088

Re: UM 1934 – Portland General Electric Company's 2018 Request for Proposals for Renewable Resources

Attention Filing Center:

Enclosed for filing is Portland General Electric Company's Reply Comments in the above-referenced docket.

Sincerely,

Loretta I. Mabinton
Associate General Counsel

LM: bp

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1934

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2018 Request for Proposals for Renewable Resources.	**REPLY COMMENTS OF PORTLAND GENERAL ELECTRIC COMPANY**

Pursuant to the scheduling order issued in this docket, Portland General Electric Company (PGE) submits these comments in support of its Draft Final 2018 Request For Proposals for Renewables Resources (2018 RFP) and in response to the Independent Evaluator's (IE) April 6, 2018 Assessment of the 2018 RFP,(Assessment), and to comments submitted by the staff (Staff) of the Public Utility Commission of Oregon (Commission), Alliance of Western Energy Consumers (AWEC) formerly the Industrial Customers of Northwest Utilities (ICNU), Renewable Northwest (Renewable NW), Community Renewable Energy Association (CREA), and the Northwest and Intermountain Power Producers Coalition (NIPPC), all on March 30, 2018. PGE appreciates the IE's and stakeholders comments, and will incorporate many of those comments, as noted below, into our Final RFP.

I. INTRODUCTION

On February 22, 2018, PGE filed a pre-issuance Draft RFP, conducted stakeholder workshops on March 2, 2018, and issued the Draft Final RFP on March 9, 2018. The Draft Final RFP incorporated feedback from the IE and stakeholders. On March 14, 2018 at a pre-hearing conference, the parties agreed to a schedule that was designed to help achieve PGE's desire to obtain maximum tax credit benefits for our customers and also to have the IE consider stakeholders' comments on the Draft Final RFP prior to issuing its Assessment.

In this 2018 RFP, PGE proposes to procure near-term renewable resources to reduce the cost to our customers of meeting our long-term Renewable Portfolio Standards (RPS) requirements. As recognized in PGE's 2016 Integrated Resource Plan (2016 IRP), PGE faces large increases in RPS compliance requirements beginning in 2030. PGE's measured procurement approach is consistent with achieving a "glide path" to RPS compliance[1] as outlined in the 2016 IRP. As acknowledged in the 2016 IRP Addendum Order No. 18-044, PGE intends to initiate its "glide path" to compliance efforts by acquiring approximately 100 MWa through this procurement process. In addition, the timing and design of the 2018 RFP provides PGE's customers the best opportunity to benefit from expiring federal Production Tax Credits (PTCs)[2] and Investment Tax Credits (ITC) while replacing a portion of PGE's capacity needs with clean energy following the cessation of coal fired operations at the Boardman coal plant.

In response to recommendations made by the IE and stakeholders, PGE will make changes to the Final RFP in the following respects:

- Adopt a more flexible approach to transmission study requirements
- Expand allowance for conditional firm bridge products
- Maintain flexibility regarding interconnection status when developing the initial short-list
- Perform price and non-price weighting sensitivity analysis

[1] A 'glide path' compliance strategy spreads RPS compliance actions and cost impacts over time as opposed to a 'just in time' strategy.
[2] In order for a project to be eligible to capture 100% of the available PTC, PGE and bidders must be ready to execute procurement agreements by the end of 2018 - barely eight months away - to allow for a 24-month construction period.

- Allow for flexible Power Purchase Agreement (PPA) pricing to pay for fixed transmission and other tariffed costs
- Use permitting status as a non-price scoring element rather than an initial threshold requirement
- Allow Schedule 202 QF projects to participate in the 2018 RFP process
- Reduce the APA/EPC (Asset Purchase Agreement & Engineering Procurement and Construction Agreement) pre-COD (Commercial Operation Date) collateral requirements from $200/kw to $100/kw
- Reduce the PPA post-COD collateral terms from five years mark-to-market to $100/kw
- Extend commitment letter requirement deadlines to the initial short-list
- Subject to Commission approval, allow for best and final offers from shortlisted bidders
- Include a planning horizon sensitivity analysis
- Eliminate non-price scoring deduction for projects subject to a Remedial Action Scheme
- Include a minimum of 150 MWa of non-benchmark resources on the short list
- Host a Post-Issuance bidder's conference
- Incorporate additional clarifications consistent with the IE's Assessment

II. REPLY

The IE's major recommendations, and material comments made by other parties are in the following areas: Transmission and Interconnection Requirements; Delivery Requirements; and Scoring Weightings. In these comments PGE will address those major recommendations, and material comments, in addition to discussion of other changes adopted by PGE, and proposals PGE is unable to adopt. We appreciate the many comments of the IE and stakeholders, many of which we agree with and some of which we do not agree with. While, as indicated above, PGE will make changes to the Final RFP to address many of these comments, it remains necessary[3] for PGE to select resources that continue to balance cost and risk for the benefit of our customers.

1. Transmission and Interconnection Requirements:

(a) PGE does not have excess transmission rights and is not hoarding transmission

PGE-M[4] currently holds 3,715MW of BPA long-term firm point-to-point transmission rights and 675MW of BPA transmission rights in deferral[5] status (discussed below). PGE's transmission portfolio goals are: (a) ensure access to the full generation capability of PGE's remote resources; (b) ensure access to the regional markets to allow PGE to meet load service obligations in a cost-effective manner while ensuring reliability and deliverability; and (c) ensure power delivery during a 1-in-10 peak load event. Current estimates for a PGE 1-in-10 peak load event, including reserve requirements, loss obligations and station service for the next ten years range from approximately 4,230MW in 2018 to almost 4,400MW in 2027. PGE must meet these projected peak load service obligations. Historical peaks, such as the 2017 load referenced by NIPPC in their comments, are not an appropriate measure for long-term transmission portfolio planning. PGE must plan generation and transmission to meet forecasted peak load service obligations with on-system and off-system resources. PGE must have the necessary transmission available to serve this peak load, and this is accomplished with a combination of network transmission for on-system resources and point-to-point transmission for off-system resources. PGE's current transmission portfolio does not contain firm transmission rights in excess of our peak load needs.

---

[3] The Commission's Competitive Bidding Guidelines require this of PGE. *See* Order No. 14-149.

[4] PGE's Power Operations area is responsible for managing generation, serving load, and managing the transmission rights used for the delivery of generation. In this comments we refer to Power Operations as PGE-M.

[5] What NIPPC ostensibly refers to as "shorter-term" positions.

As discussed above, PGE-M's transmission portfolio includes network transmission for on-system resources and point-to-point transmission for off-system resources. These comments focus on PGE-M's BPA point-to-point transmission rights that are the subject of stakeholder comments. Attachment A identifies these BPA transmission rights and is organized to show the rights held for each PGE resource. These transmission rights historically, and today, are used to move generation from remote resources to serve load, and to provide access to regional power markets for the benefit of our customers.

PGE-M's 675MW of deferred transmission rights are not currently active. Deferral of transmission service under BPA's Open Access Transmission Tariff (OATT) is available to a BPA customer with an executed point-to-point transmission service agreement. Such BPA customer may defer[6] the service commencement date of transmission service five times for up to one year each time (maximum total deferral for five years from the original start date). Each time a customer elects to defer their transmission rights, they must pay a fee to BPA in order to do so. PGE has not included any deferral fees or other fees associated with these deferred rights in customer rate, rather PGE shareholders have borne the risk and cost of such rights. PGE-M plans to layer in[7] these deferred transmission rights as other currently active BPA transmission rights begin to expire (as opposed to supplementing existing rights). PGE has NOT and is NOT

[6] In its comments, CREA asserts that, "Once PGE signs a long-term firm point-to-point transmission agreement, BPA must reserve the capacity and make it unavailable for any other bidder…" However, under BPA's competition procedures for deferral service, BPA will identify "challenger" (customer requesting rights) and "defender" (customer deferring rights) requests that meet certain criteria. Through BPA's process a defender can be forced to forfeit its rights to the challenger.

[7] At which time they will be included in customer rates. AWEC argues that "PGE customers pay for the Company's transmission rights…." While PGE does recover the expected cost of BPA transmission rights via the Annual Update Tariff, the costs and transmission rights included in PGE's power cost forecast are only those transmission rights which are currently providing service to PGE customers. The costs associated with transmission rights that are in a deferred state are borne entirely by PGE and not included in customers' rates.

engaged in hoarding of BPA transmission, and actively manages its transmission portfolio in order to meet our reliability obligations and manage power costs for our customers.

In their comments, some parties proposed that PGE should make its transmission rights available to all bidders, requiring PGE to renew and redirect expiring rights on behalf of third parties. These parties have generally overlooked the substantial financial risk, redirect[8] risk, and renewal risk this would unnecessarily place on PGE and its customers. PGE cannot commit to a five year transmission renewal contract with BPA on behalf of third parties. It is not reasonable to expose PGE customers to the financial risk associated with transmission service while the third parties who MAY use such transmission have no exposure to those risks.[9] This risk is compounded because if such assumed beneficiary (a bidder) of the renewal fails to energize it's facility or otherwise fails to honor the terms of the transmission agreement, then PGE, although it does not currently expect it has the ability to utilize the renewed transmission rights, will nonetheless be stuck with the costs. Contrary to NIPPC's suggestion that PGE's expiring rights "can redirect to almost anywhere in the region,"[10] these rights are not broadly redirectable.[11]

(b) PGE's Benchmark Resource is NOT using PGE-M's Transmission and Will Be Subject to the Same Bidding Requirements

[8] On BPA's system, a customer with existing point-to-point transmission rights can submit a request to move those rights from one POR/POD combination to a different POR/POD combination on a long-term basis. This process is known as redirecting.

9 In fact, bidders financial exposure to BPA can be mitigated or limited through project entities whereas should PGE be unable to meet its financial obligations to BPA, PGE's service for all BPA transmission would be at jeopardy.

[10] NIPPC at page 6.

[11] In order to understand redirect risk on BPA's system, it is important to understand how BPA evaluates available capacity. When BPA assesses transmission availability for either new service or a redirect, it evaluates the impacts of each request on specific system constraints, known as flowgates. Not all requests have the same flowgate impacts and just because two requests are similar, they may not be equally viable. In order for a request to be granted, BPA must have sufficient capacity on all impacted flowgates, not just a specific subset. For this reason, PGE's transmission rights, both active and deferred, are not broadly redirectable to any part of the BPA system as parties indicated. In the last two years, PGE has had multiple redirects that were placed in the queue due to insufficient capacity, granted for only a part of the requested term, or granted for the term and given no renewal rights on the new POR/POD.

PGE will evaluate all bids, including the PGE benchmark bid, consistent with the 2018 RFP requirements. As such, the benchmark bid will need to demonstrate a reasonable and achievable plan to obtain long-term firm transmission rights from the resource to the specified delivery point that does not rely upon assignment of any PGE-M transmission rights.[12] The 2018 RFP is designed to be fair, transparent and equitable to all bidders. The design is consistent with the IE's recommended standard that, "the 'benchmark' offers [be] treated in the same manner as non-affiliate bids---that is, held to the same qualification and offer requirements."[13] PGE can support CREA's recommendation that the Commission audit the application of PGE's BPA transmission rights[14]

(c) Long-term firm transmission is required for reliable service

In addition to long-term firm (LTF) transmission, BPA offers short-term firm[15] (STF), non-firm (NF), and Conditional Firm (CF) transmission products. Contrary to NIPPC's comments, CF and NF transmission products are of lower priority, meaning they are curtailed before LTF, and dependability since there is no obligation on the transmission provider to make them available, and will continue to degrade as the system becomes increasingly constrained. BPA has confirmed it will not move forward with the I-5 Corridor project and instead will rely on other products, such as CF Reassessment[16], to help expand the utilization of the transmission system. NIPPC would have the Commission and stakeholders believe that these products are

[12] Contrary to NIPPC's unsubstantiated allegations. See NIPPC comments at page 4.
[13] IE Assessment at page 4.
[14] See CREA comments at page 6.
[15] Short-term is defined as transmission service that can be reserved no more than 365 days in advance and has a duration of less than 364 days with an end date no later than 13 months from the request date. Long-term is defined as transmission service that can be reserved up 10 years in advance and has a duration of no less than 12 months and no more than 30 years. See Section G.2 of https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/Requesting-BP-V35.pdf.
[16] CF Reassessment is a type of transmission service where every two years BPA reassess the number of hours and/or system conditions under which BPA can curtail the service.

adequate and relatively low risk, but fail to point out that the reliability of these products are limited and will become increasingly so as usage grows.

BPA's CF transmission service is a type of transmission service for which there is a specified number of hours per year or specified system condition in which the Transmission Provider can curtail the reservation prior to curtailing other LTF service. CF products vary in certainty of deliverability and curtailment potential as well as by the potential to convert the transmission service to LTF. To qualify for BPA's CF Bridge[17] service, a customer must commit to participate in the necessary system upgrades for impacted flowgates and BPA must have either LTF and/or CF inventory available to offer.[18] Upon completion of the upgrades, the CF Bridge will then convert to LTF transmission rights. BPA's CF Reassessment service is a type of CF Service in which the Transmission Provider has a right, no more than once every two years, to unilaterally modify the number of hours or terminate service to maintain reliability.[19] To clarify, once every two years, BPA can reassess the service and based on system conditions, could increase or decrease the number of hours the transmission would be subject to CF curtailment, terminate the service, or offer a path to CF Bridge service. There is no guaranteed path for CF Reassessment service to convert to LTF service.

As part of this RFP, PGE will entertain bids that rely upon a CF Bridge product, as this product will convert to LTF when the bridge condition is met. Since CF Reassessment does not provide a certain path toward LTF transmission, and a reassessment could result in decreased reliability or termination, this is not a risk that is reasonable for PGE and its customers to bear.

---

[17] CF Bridge is a type of transmission service that converts to LTF if the transmission facilities identified in the Service Agreement or their equivalent are completed or if LTF service otherwise becomes available. See Section I of BPA Conditional Firm Transmission Service Business Practice at https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/Conditional-Firm-BP-V21.pdf.

[18] Section B.4 of BPA Conditional Firm Transmission Service Business Practice at https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/Conditional-Firm-BP-V21.pdf.

[19] Section 1(f) of the BPA Condition Firm Service Agreement.

NIPPC states that "long-term firm transmission arbitrarily inflates resource costs and provides no increased reliability benefits."[20] This is demonstrably false.[21] BPA states that certain transmission products, including CF, will be curtailed ahead of LTF transmission products during stressed system conditions. As recognized in the 2016 IRP, renewable resources contribute to meeting PGE's capacity adequacy requirements during stressed system conditions and therefore cannot rely upon unpredictable transmission. Or can PGE forecast the magnitude by which reassessed transmission products will degrade a resource's energy delivery. It appears that NIPPC would have the Commission assume that these products are of equal reliability and have PGE invent methods to assess the resource value impact associated with CF. As shown above, these transmission products are not of equal reliability and cannot be compared on a long-term basis without speculation.

(d) BPA's Transmission Study Process

Off-system resources without transmission rights to PGE can participate in BPA's TSEP[22] transmission study process or to be an individual study process to acquire transmission rights. In the Draft Final RFP, PGE sought to balance two goals: 1) Allow for reasonably broad bidder participation, and 2) PGE's customers potentially losing out on the opportunity to acquire top-performing resources eligible for maximum expiring tax credits while waiting for resolution of BPA's study process. Comments from RNW and the IE encouraged PGE to refine the Draft Final RFP's BPA TSEP study progress requirements that would allow for additional bidder participation. Therefore, PGE will consider any bid participating in the 2016 TSEP or that is in

[20] NIPPC comments at page 10.
[21] BPA's Conditional Frim Transmission Service Business Practice states "Conditional Firm Transmission Service is a type of Long-Term Firm transmission service for which there is a specified Number of Hours per year or specified System Condition in which the Transmission Provider can curtail the reservation prior to curtailing other Long-Term Firm service." Available at https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/Conditional-Firm-BP-V21.pdf.
[22] TSEP - Transmission Study and Expansion Process.

an individual study process to have met PGE's reasonable and achievable transmission plan standard for the purposes of meeting the initial thresholds. PGE will require evidence of all BPA transmission upgrade cost estimates before selecting the initial shortlist. Furthermore, if before final negotiations a bidder has not received a commitment from BPA for a viable pathway to LTF service, PGE reserves the right to execute agreements only with bidders that have received such commitments.[23] Also, to allow for additional flexibility and potential changes in BPA timelines, PGE's Final 2018 RFP will extend the acceptable period of CF Bridge service from one year to two years. This change should increase the number of upgrades identified in the 2016 TSEP that will be able to support bids' transmission plans.

(e) Interconnection Requirements

PGE will work to maintain flexibility regarding interconnection status when developing the bidder short-list, but reserves the right to not place a bid on the short-list if it has not advanced in the interconnection process and is unable to provide adequate timing and cost estimates. PGE acknowledges that bidders do not directly control the interconnection process; however, bidders have means to actively accelerate the process. As between PGE and the bidder, the bidder is better able to mitigate any off-system interconnection related risks by taking actions related to its BPA request. Therefore, it is unreasonable to expect PGE to solve bidder interconnection challenges.[24] Contrary to NIPPC's suggestion[25], PGE cannot provide a blanket waiver for interconnection delays and put at risk the potential to capture expiring tax credit benefits for customers.

[23] BPA's commitment for long-term firm service will be evidenced through completion of phase four of BPA's TSEP process or through definitive agreements issued through BPA's individual study process.
[24] PGE is not even privy or party to the interconnection negotiations for off-system resources.
[25] NIPPC at page 28.

PGE notes there is an inconsistency in the 2018 Draft Final RFP documents issued on March 9, 2018 - the inconsistency is between the RFP Main Document (Section 6.2.7) and Appendix H (Exhibit A, Question 3.a) for the Interconnection requirement. PGE will clarify in the 2018 Final RFP that all bids with an off-system resource(s) will need to complete an Interconnection Facility Study before the short list determination. PGE will update both the 2018 Final RFP main document and Appendix H to eliminate the inconsistency.

2. Delivery Requirements.

a) 60-minute Scheduling

In past RFPs, PGE considered sub-hourly scheduling and acknowledged the cost of balancing services associated with 60-minute scheduling. However, the operating paradigm has materially changed since those RFPs were issued and using a 60-minute scheduling duration and the specific scheduling timing requirements in the Final Draft RFP addresses cost shifting while allowing for a scheduling practice to be applied to all bids, including the benchmark bid, to ensure fairness and equitable treatment.

Using a scheduling duration shorter than 60 minutes for off-system resources[26] will shift costs from a project owner to PGE, and thereby mask the total cost of the bid. When variable resources' generation differs from hourly forecasts, incremental costs are incurred by requiring additional online generation that responds to the intra-hour changes. Furthermore, schedule changes after the EIM base schedule submission deadline will create imbalance charges or credits that will be assessed to PGE (and not reflected in the resource owner's bid). PGE will be unable to manage these charges or credits because the resource is not eligible to submit bids or

[26] PGE notes that on-system resources are not scheduled because they are not interchange transactions and do not require NERC e-tags.

respond to automated signals from the EIM. Therefore, all off-system projects, including the benchmark bid, will be evaluated using the same scheduling requirements.

Some parties have pointed out the possible diversity benefit of sub-hourly scheduling. However, 60-minute scheduling similarly provides diversity benefit without the cost-shifting impacts of intra-hour scheduling. Resources can still provide for offsetting increases/decreases in schedules every 60-minutes (e.g. two wind resources in different wind conditions) and-regardless of schedule duration- can have diverse energy profiles over a day or a season (e.g. solar coupled with wind).

b) Balancing Services and Dynamic Transfer

In order to ensure the 2018 RFP is fair and equitable, PGE has made it clear that all off-system bids, including the benchmark bid, will be required to provide balancing services. At this time, it is inappropriate to require PGE to accept additional pseudo-ties of large quantities of additional variable energy resources. The 2018 RFP requirements regarding balancing services and dynamic transfer are competitive, equitable, and fair.[27]

Some parties have raised concerns that the risk of future (higher) cost of these services are not equal between a PPA and an ownership option as they have assumed that a PPA has to make some assumption about the escalation of balancing service costs while an ownership option would simply be able to pass them through to customers. To address this concern, PGE included in its initial 2018 RFP design the ability for bidders to submit both variable and fixed costs and

[27] PGE's requirements are consistent with recently executed contracts and NIPPC's comparisons to the PacifiCorp draft PPA are mischaracterized and misleading. NIPPC ignores the following features of the PacifiCorp PPA: PacifiCorp PPA is clearly for on-system resources only, which do not require a pseudo-tie or third party balancing services; and the PacifiCorp draft PPA provides that the "***Seller** shall be responsible for paying or satisfying when due all costs or charges imposed in connection with the scheduling and delivery of Net Output **up to and at the Point of Delivery**, including transmission costs, Transmission Service, and transmission line losses…*", which, if applied to an off-system resource, includes balancing services. See PacifiCorp RFP PPA App E-2 § 5.2 (Costs and Charges).

invited bidder to propose changes to the draft PPA.[28] A bidder could also elect to include such charges in the variable price and assume some level of risk, but retain the benefit if the actual charge was lower than the forecast included in development of the bid price. For utility owned resources, a reduction in the balancing service or other tariffed charges over time would be credited to customers.

Some parties proposed in their comments that the Commission should direct PGE to allow dynamic transfer and pseudo-tie by making use of PGE resources to balance the intermittent output of third-parties variable energy resource.[29] This, they assumed will avoid the cost of a transmission provide balancing services. This is a faulty assumption. In this 2018 RFP, PGE has not proposed the use of dynamic transfer for an off-system resource for the following reasons:

i. Requiring third-party pseudo-ties would create onerous and complex contracting and settlement requirements

ii. Requiring third party pseudo-ties would shift costs and risks to PGE and its customers

iii. Requiring third party pseudo-ties could jeopardize PGE's safety & reliability

iv. Neither PGE-Transmission[30] nor BPA has studied or confirmed the ability of any of the resources that may bid into RFP to pseudo-tie to PGE's system

BPA has explicit requirements for establishing dynamic schedule or pseudo-tie. BPA has made its Dynamic Transfer Operating and Scheduling Requirements business practices available to all.

---

[28] Conceivably, a bidder could submit a PPA that has a fixed cost component equal to the cost of the balancing services or could provide redlines that allow for the adjustment of such charges, if they change during the period of the contract, effectively passing the charges through to PGE.

[29] For the sake of clarity, PGE assumes that parties are using terms such as dynamic scheduling, pseudo-tie, and dynamic transfer interchangeably. PGE notes that dynamic schedules and pseudo-ties are mutually exclusive types of dynamic transfer.

[30] PGE-Transmission is the functional area within PGE that is responsible for the transmission system operations and balancing authority operations.

PGE highlights some of those eligibility requirements:

i. *"A generator that is Dynamically Transferring its full output…outside of the BPA Balancing Authority must do so using a Pseudo-Tie...."* This means the only viable method for dynamically transferring the entire net output of a facility is a pseudo-tie, placing all obligations on PGE.[31]

ii. *"New requests for Dynamic Transfer on BPA's network are subject to BPA's Requesting Access to Dynamic Transfer Capability (DTC)…"* The DTC business practice outlines the process for requesting DTC and the steps/evaluations BPA will take before offering DTC to the requestor.[32]

iii. *"The Dynamic Transfer Entity may only affect Dynamic Transfers on BPA's transmission system with firm transmission rights."* Given the 20-year minimum term requirement in the RFP, this can only be achieved by using LTF transmission, as opposed to the use of other products as proposed by NIPPC and RNW in their comments.[33]

The Biglow and Tucannon windfarms were the first variable energy resources to be pseudo-tied into the PGE BAA.[34] Given that PGE has only had four months of experience with Biglow and Tucannon pseudo-tied in the PGE BAA, PGE does not have the data for studying the amount of variable energy resources it could successfully integrate without material impacts to cost and reliability.[35]

Overtime PGE will use the experience gained in integrating Biglow and Tucannon to develop and refine operational cost estimates and protocols for broader resource integration. However, today PGE does not currently have a tariffed ancillary service, and does not have the detailed estimates that RNW suggests to publish and charge to bids.

---

[31] https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/DTC-Operating-Scheduling-Reqs-BP-V07.pdf at Section A.5.
[32] *Id* at Section B.1. Dynamic Transfer Capability across the BPA transmission system is a pre-requisite for implementing dynamic transfer.
[33] *Id* at Section B.4
[34] PGE completed the dynamic transfer of both Biglow Canyon (Biglow) and Tucannon River (Tucannon) into the PGE Balancing Authority Area (BAA) in December 2017.
[35] PGE's comments address the cost shifting impacts earlier in this section.

It is worth noting that once a pseudo-tie is implemented, the resource and all associated reliability and operating obligations are transferred to the receiving BAA. This practice effectively moves the resource inside the metered boundaries of the BAA. A pseudo-tied resource cannot simply be scheduled on/off or up/down like a party would do when scheduling a resource's output from one BAA to another. For this reason, and reasons identified above, PGE has determined that the potential liability, compliance risks, contractual complications and control risks[36] associated with 'controlling' a third party's resource is not in the best interest of PGE's customers or shareholders.

3. Scoring Weighting.

PGE's 2018 RFP proposes a reasonable and proven balance of price and non-price scoring. Some parties have suggested that PGE's proposed weighting of project non-price scores may be too high. Staff and the IE recommend that PGE include price, non-price weighting sensitivities within PGE's RFP analysis to demonstrate the reasonableness of PGE's bid evaluation design. PGE welcomes this feedback and will include a sensitivity analysis of PGE's price, non-price weighting as a part of PGE's shortlist analysis. For reasons described below, PGE continues to believe it remains appropriate to base procurement decisions on the proposed 60/40 price, non-price weighting design.

To combine price and non-price factors, it is necessary to convert price and non-price factors to common unit. Consistent with Guideline 9a[37], PGE uses a bid's price score ratio to assign a bid's price score and assigns sixty percent of the total available score to the price score

---

[36] For example, the ability to reduce/increase output, shut the facility off, or remotely activate devices such as circuit breakers.

[37] "… selection of an initial shortlist should be based on price and non-price factors". Order 14-149 Appendix A page 3.

ratio. A bid's non-price score is assigned using PGE's non-price scoring rubric evaluating the project specific risks, resource characteristics, and other important bid attributes not captured in the bid's price score ratio. Forty percent of the total available score is determined by the bid's non-price scoring rubric. The proposed balancing of project cost and risk is referred to by parties and PGE as a 60/40 price, non-price weighting.

PGE continues to believe the 60/40 price/non-price weighting is reasonable because it prioritizes the selection of least cost resources while providing a meaningful balance between cost and risk. The purpose of non-price scoring is to acknowledge the important benefits and risks associated with a proposed project that cannot be practically expressed in a bid's price. For example, the performance of a resource with seven years of historical facility generation data can be better estimated than a resource with only three years of data. Certainly there is value related to increased confidence in forecasted bid performance, but PGE cannot express this benefit in terms of dollars saved for customers. For that reason it is appropriate to assign non-price benefits for resources with more data. It is appropriate and important to evaluate risk qualities through the use of non-price factors. In the alternative, an RFP scoring design can eliminate non-price scoring and instead make bidder eligibility requirements more stringent requiring all bids to provide the desired non-price qualities. However such an alternative RFP design limits resource participation and competition by potentially excluding high value resources that may not be able to meet those more stringent requirements. RFP designs that include non-price scoring criteria protect customers from higher risk resources while also allowing for reasonably broad bidder participation.

Some parties suggest that non-price scoring reduces the transparency of the RFP scoring design. PGE disagrees that non-price scoring diminishes the transparency of the solicitation. In this 2018 RFP, PGE has disclosed the full detail of its non-price scoring rubric. The proposed scoring design is transparent to all bidders and stakeholders. Sufficient detail is provided so that all bidders should be able to reasonably estimate the applicable non-price score for their bids.

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 Order No. 91-1383. In Docket UM 316, Staff recommended that RFPs be required to utilize a non-price scoring weight between thirty and fifty percent.[38] The Commission adopted this requirement.[39]

In any event, PGE's 2018 RFP design places a much higher emphasis on price scoring in comparison to prior PGE procurements processes through the use of a cost containment screen. Staff, NIPPC, and the IE suggest that price scores should be mostly determinative of bid selection. PGE reminds stakeholders and the Commission that the proposed use of a cost containment screen within the analysis makes price scoring largely determinative of resource outcomes. In this RFP, in order to be eligible for consideration for PGE's shortlist, bids must have a price score ratio less than one. Non-price scoring is not considered when applying this cost-containment screen. Thus, non-price scoring will only serve to distinguish those bids that have already demonstrated superior price performance through passing the cost containment screen.

In response to Staff's and the IE's suggestions, PGE will incorporate a price/non-price sensitivity analysis into its shortlist evaluation to demonstrate the reasonableness of the proposed

[38] Order No. 91-1383 at page 18.
[39] Order No. 91-1383 at page 19.

scoring weighting. Specifically, PGE will study how the ranking of its initial shortlist would be affected by 70/30 and 50/50 price[40], non-price weighting sensitivities.

III. OTHER

1. Permitting.

In the Draft Final RFP, PGE identified threshold requirements for major permits applied at either bid submittal or at the final shortlist determination. The permitting requirements were designed to ensure that bids will receive the required permits to support the project COD. The IE has suggested that those requirements be relaxed. PGE will incorporate the IE's recommendation that specific permitting milestones not be threshold requirements. PGE will use the permitting requirements table in Appendix H to determine a bidder's ability to meet the permitting requirements and will work with the IE to exclude those offers that in PGE's judgment cannot meet the permitting requirements.

2. Qualifying Facilities (QF).

Consistent with the Commission's Competitive Bidding Guideline number 6, PGE invited QFs of 10MW or more to participate in this RFP. Such QFs retain all of their rights under the law, including the right to sell their output as QFs if they so choose. The Draft Final RFP was designed to protect the sanctity of contracts. This RFP should not incent or provide the basis for project owners to breach their agreements or allow project owners to game the system. Every counter party to a contract has agreed to honor the terms and conditions of their contract. Nonetheless, some parties have indicated a desire for QF projects, under existing contracts, to participate in the RFP. PGE will welcome the participation of these QF projects in this RFP because of the potential of their bids to provide lower prices for our customers than their current

[40] In UM 1892 Staff encouraged PGE to apply more weighting to non-price factors by using a 50/50 price, non-price weighting.

avoided costs prices. PGE is willing to let such developers bid into the RFP but, in doing so, makes no commitment as to whether it would be willing to mutually terminate an existing Schedule 202 contract. PGE will make that determination on a case-by-case basis in the best interest of our customers.

3. Credit and Bidder Qualifications.

The IE's Assessment provides additional guidance and recommendations regarding PGE's proposed performance assurance requirements. Specifically the IE offered certain recommendations regarding the use of letter of credit commitment letters for credit and/or guarantees, the reasonableness of proposed pre-COD performance assurances for APA/EPC structures and the reasonableness of proposed post-COD performance assurances for PPA structures. The IE recognizes that the use of commitment letters is a reasonable way to reduce bidder costs, but suggests that this requirement be applied upon selection to the shortlist.[41] PGE welcomes this suggestion and will modify the Final RFP to require a Letter of Credit or Guarantor Commitment letter at the shortlist phase.

PGE's Final Draft RFP pre-COD requirements for APA/EPC bidders required a $200/kW collateral and a 100% payment and performance bond. The performance assurances are designed to protect customers. In the Assessment, the IE believed the APA/EPC requirement for a 100% performance bond *in addition to* substantial pre-COD credit was excessive.[42] In response to the IE's concern, in the Final RFP, PGE will reduce the pre-COD collateral requirement to $100/kW rather than the $200kW contained in the Final Draft RFP for APA/EPC bids.[43] We

[41] IE Assessment at page 9.
[42] IE Assessment at page 5, emphasis in Assessment.
[43] The final performance assurances and credit lines extended to parties will be a subject of final negotiations.

will also clarify that there is no requirement of a performance or payment bond for APA-only bids.

In the Draft Final RFP, PGE proposed a five-year Mark-to-Market (MtM) post-COD collateral requirement to protect PGE customers from project default. Credit exposure presents real risks to companies, and MtM collateral calculation is a standard mechanism to manage exposure. If a project owner decides to terminate the contract to benefit from a higher priced sale, PGE's customers could be left to replace the existing contracts with potentially higher priced power. However, both Staff[44] and the IE encouraged PGE to reconsider the post-COD collateral requirements for PPA structures.[45] In response to Staff and the IE's comments, in the Final RFP PGE will include a $100/kW PPA post-COD collateral requirement in lieu of MtM calculations.

4. Best and Final Offers.

The IE suggests that PGE allow for bidders to update offers to include best and final pricing. At the time of RFP design, PGE was concerned that allowing for pricing updates, for all bidders, including the benchmark bid, may not be consistent with the Commission's Competitive Bidding Guideline 8 which requires the benchmark bid be evaluated and sealed before third party bids are received. However, PGE recognizes that there may be a benefit to allowing for best and final price updates. PGE is willing to make this change to the RFP should the Commission agree that such a design is consistent with its Competitive Bidding Guidelines.

5. Other Enumerated Changes to the Final RFP.

a) PGE will include a minimum of 150 MWa of non-benchmark resources on the short list provided there are sufficient bids that have passed PGE's cost containment screen.

[44] Staff comments at page 5.
[45] IE Assessment at page 5.

b) In the Final RFP, PGE will include a Net Present Value Revenue Requirement planning horizon sensitivity analysis.

c) PGE will eliminate the non-price scoring deduction for projects subject to a Remedial Action Scheme.

d) The Final RFP will include several clarifying edits identified in the IE Assessment.

IV. CHANGES PGE IS UNABLE TO MAKE

a) Project Owners Should Be Responsible for the Costs of Intra-Year Variability and Unpredictable Generation.

As renewable resources become the primary element of PGE's power portfolio, it is unreasonable to require PGE to bear the costs related to the intra-year variability of third-party owned renewable resource generation. Each bid's price should reflect the total cost associated with the project so that bids are evaluated fairly and correctly. Resource costs, including the variability of resource generation, should be managed by the project owner, PGE or otherwise. This cost and risk allocation is reflected in the form PPA. PGE carefully drafted the form PPA to fairly assign costs of project variability utilizing the terms and conditions related to 'Specified Energy'. As such, the form PPA reflects the *preferred* terms and conditions that PGE seeks from bidders. Importantly, PGE has recently signed PPAs with developers of renewable resources including these very same provisions. The presence of these agreements indicates that many bidders are able and willing to be responsible for the variability associated with their projects, and are pricing those costs into their PPA prices. Furthermore, as is provided in the Draft Final RFP, bidders are welcome and encouraged to redline the form PPA and offer alternative terms and conditions.

b) PGE should be able to rely on the obligations and commitments of the Seller throughout the term of the PPA.

It is unreasonable to hold PGE to a standard of certainty and reliability throughout the product lifecycle (development, planning, forecasting, scheduling, dispatch, project maintenance, etc.) that is different than that for sellers. PGE views a PPA where the seller holds the right to intentionally breach and pay damages, in lieu of fulfilling its obligations under the PPA, as unacceptable and has incorporated provisions designed to prevent a seller from benefiting from its own default.

c) Rate Making Determinations Should Not Be Made In This Proceeding.

In the Assessment, the IE suggested that the Commission make a rate making determination in the RFP acknowledgment order regarding the potential recovery of the costs of a benchmark resource.[46] PGE disagrees. PGE is responsible for controlling potential project costs in line with bid estimates. Under the current regulatory construct, the appropriate time to make a prudency determination is in a rate case, not in a RFP acknowledgment docket. Indeed the Commission reached the same conclusion in Order No. 17-345 when it acknowledged PacifiCorp's Final Draft RFP.[47]

d) Preferred Commercial Operations Date.

In its Comments, AWEC has suggested that PGE delay its required COD to 2023. AWEC implies that a COD extension would allow for bidders with less developed project plans to participate. PGE is unwilling to delay its required COD and possibly forgo low cost opportunities prepared to deliver in 2021 or earlier. However, those bids relying on the 30% ITC

---

[46] IE Assessment, See page 8.

[47] The Commission writes: "With regard to potential benchmark bid bias in RFP terms, we made clear that a future Commission would consider cost overruns and change orders in a prudence review, but did not commit to holding PacifiCorp accountable for benchmark bids' cost and performance assumptions." See Order No. 17-345 at page 4.

are encouraged to participate in the solicitation. Contrary to the fears expressed by AWEC[48], if PGE finds proposed resources are not cost competitive as expected, PGE will not procure any renewables through the 2018 RFP and may consider a subsequent solicitation at a later time.

e) **Required Data.**

In order to properly evaluate proposed bids, PGE requires reasonably sufficient bidder data to assign the resource value. To assign capacity value to renewable resources, PGE requires a sufficient period of estimated historical generation. PGE's Final Draft RFP requires a minimum of three years of historical generation. In comments NIPPC recognized the data requirement to be reasonable.[49] RNW also does not dispute the reasonableness of this requirement but instead suggests the RFP should provide clarity to be consistent with responses provided by PGE in the pre-issuance bidder workshop.[50] The IE suggested that PGE should reduce the resource data requirement to one year.[51]

PGE does not agree that a shorter length of historical data requirement would be appropriate in this solicitation. As communicated to stakeholder and bidders through PGE's application and the pre-issuance workshops, PGE requires the historical generation data in order to assign renewable resources a capacity value consistent with the methods used in the 2016 IRP. In response to Staff Data Request No. 11, PGE explained how the accuracy of PGE's capacity contribution analysis could be significantly reduced for bidders with less than three years of estimated historical generation. Specifically, PGE demonstrated that a bid with only one year of historical data could be assigned a capacity contribution that was 26% higher than the more precise capacity contribution identified for the same resource with three years of data. In the

[48] AWEC at pages 2-3.
[49] NIPPC at page 38.
[50] RNW at page 11.
[51] IE Assessment at page 10.

interest of accurately assigning value to bids, PGE will require at least three years of estimated historical generation data. Lowering the requirements could distort the evaluations to the detriment of PGE's customers.

V. CONCLUSION

PGE is seeking to achieve a balance of least cost and least risk in identifying resources through the 2018 RFP, while engaging in an accelerated timeline to ensure that the value of expiring PTCs are captured for the benefit of customers. In order to allow for eighteen (18) to twenty-four (24) month construction period, 100% PTC eligible projects will require executed agreements by the end of 2018. Due to this timing requirement, this solicitation will be unable to extend the RFP schedule or final negotiations and achieve the 100% PTC eligibility. For this reason PGE has included requirements designed to demonstrate project preparedness and commitments consistent with the requirements to quickly and efficiently complete final negotiations and due diligence.

PGE's Final 2018 RFP, incorporating the changes recommended by stakeholders and discussed in these reply comments, will be consistent with the Commission's Competitive Bidding Guidelines, is expected to attract competitive bids, and is likely to result in PGE's procurement of least-cost, least-risk resources on behalf of our customers. PGE requests that the Commission issue an order approving the 2018 RFP process to acquire approximately 100 MWa of renewable energy resources.

DATED this 13th day of April, 2018.

Respectfully submitted,

Loretta I. Mabinton, OSB#020710
Associate General Counsel
Portland General Electric Company
121 SW Salmon Street, 1WTC1301
Portland, Oregon 97204
(503) 464-7822 (phone)
(503) 464-2200 (fax)
loretta.mabinton@pgn.com

ATTACHMENT A

PGE Merchant BPA Point-to-Point Transmission Rights

Resource	TSR	Type	POR	POD	MW	EXPIRATION
PW1, PW2, Beaver	**79042492**	**PTP LTF**	**TROJAN**	**BPAT.PGE**	**531**	**1/1/2020**
SLATT Carty, Boardman	**84036952**	**PTP LTF**	**SLATT**	**BPAT.PGE**	**949**	**Aggregated**
	79099585	PTP LTF	SLATT	BPAT.PGE	279	1/1/2021
	78857909	PTP LTF	SLATT	BPAT.PGE	45	11/1/2019
	81460445	PTP LTF	SLATT	BPAT.PGE	100	11/1/2019
	80394113	PTP LTF	SLATT	BPAT.PGE	50	1/1/2021
	83330505 / 83675039	PTP LTF	SLATT	BPAT.PGE	55	1/1/2021
	83344982 / 83675061	PTP LTF	SLATT	BPAT.PGE	20	1/1/2021
	81827800	PTP LTF	SLATT	BPAT.PGE	50	5/1/2021
	81827802	PTP LTF	SLATT	BPAT.PGE	50	5/1/2021
	81827805	PTP LTF	SLATT	BPAT.PGE	50	5/1/2021
	81827807	PTP LTF	SLATT	BPAT.PGE	50	5/1/2021
	81827809	PTP LTF	SLATT	BPAT.PGE	50	5/1/2021
	81827810	PTP LTF	SLATT	BPAT.PGE	50	5/1/2021
	83330491 / 83717595	PTP LTF	SLATT	BPAT.PGE	50	1/1/2021
	84036952 / 85945599	PTP LTF	SLATT	BPAT.PGE	50	1/1/2021
Colstrip - Three legs required from plant to PGE	76112603	PTP GF	TOWNSEND	GARRISON	280	10/1/2027
	79042267	**PTP LTF**	**GARRISON**	**BPAT.PGE**	**270**[52]	**1/1/2020**
	76059414	PTP LTF	COLSTRIP	TOWNSEND	307	7/1/2022

[52] The Colstrip plant requires three legs of transmission to get from the plant to BPAT.PGE. Colstrip to Townsend is PGE transmission, Townsend to Garrison and Garrison to BPAT.PGE are two different BPA legs. The most restrictive leg of the three is Garrison to BPAT.PGE at 270MW, so that limits the amount of generation that can flow on the entire path.

Resource	TSR	Type	POR	POD	MW	EXPIRATION
Coyote Springs			COYOTESPRNG1	BPAT.PGE	**275**	
	79042182	PTP LTF	COYOTESPRNG1	BPAT.PGE	250	1/1/2020
	83662087	PTP LTF	SLATT (redirecting)	BPAT.PGE	25	1/1/2023
MIDC	**86073439**	**STF Monthly**	**ColumbiaMKT**	**BPAT.PGE**	**788**	**Aggregated**
	79099468	PTP LTF	MIDCREMOTE	BPAT.PGE	161	1/1/2020
	79734273	PTP LTF	MIDCREMOTE	BPAT.PGE	300	6/1/2020
	79099396	PTP LTF	MIDCREMOTE	BPAT.PGE	27	1/1/2020
	79109702	PTP LTF	MIDCREMOTE	BPAT.PGE	131	1/1/2020
	79099506	PTP LTF	MIDCREMOTE	BPAT.PGE	169	1/1/2020
	79099382	**PTP LTF**	**MIDCREMOTE**	**JOHNDAY**	**150**	**1/1/2020**
Biglow	**84034317**	**PTP LTF**	**BIGLOW**	**BPAT.PGE**	**450**	**Aggregated**
	79058520	PTP LTF	BIGLOW	BPAT.PGE	150	6/1/2020
	79058581	PTP LTF	BIGLOW	BPAT.PGE	50	10/1/2020
	79058669	PTP LTF	BIGLOW	BPAT.PGE	250	10/1/2020
Tucannon	**84036021**	**PTP LTF**	**CNTRLFRRY230**	**BPAT.PGE**	**267**	**Aggregated**
	81460014	PTP LTF	CNTRLFRRY230	BPAT.PGE	10	1/1/2025
	81460326	PTP LTF	CNTRLFRRY230	BPAT.PGE	25	1/1/2025
	81460336	PTP LTF	CNTRLFRRY230	BPAT.PGE	25	1/1/2025
	81460381	PTP LTF	CNTRLFRRY230	BPAT.PGE	50	1/1/2025

Resource	TSR	Type	POR	POD	MW	EXPIRATION
	81460390	PTP LTF	CNTRLFRRY230	BPAT.PGE	50	1/1/2025
	81460394	PTP LTF	CNTRLFRRY230	BPAT.PGE	25	1/1/2025
	81460417	PTP LTF	CNTRLFRRY230	BPAT.PGE	25	1/1/2025
	81460428	PTP LTF	CNTRLFRRY230	BPAT.PGE	7	1/1/2020
	81460466	PTP LTF	CNTRLFRRY230	BPAT.PGE	50	1/1/2025
Vansycle	83330494	PTP LTF	VANSYCLE	BPAT.PGE	**25**	7/1/2019
Biglow and Tucannon Station Service	79593334	PTP LTF	MIDCREMOTE	CNTRLFRRY230	**5**	1/1/2020
	79593338	PTP LTF	MIDCREMOTE	BIGLOW	**5**	1/1/2020