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Loretta I. Mabinton
Associate General Counsel

April 30, 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 Response to Staff's Report in the above-referenced docket.

Sincerely,

Loretta I. Mabinton
Associate General Counsel

LM: sj

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.	**PORTLAND GENERAL ELECTRIC COMPANY'S RESPONSE TO STAFF'S REPORT**

Portland General Electric Company (PGE) appreciates this opportunity to respond to the Public Utility Commission of Oregon's (Commission) Staff's Report[1] on PGE's Draft Final Request for Proposals for Renewable Resources (RFP) and appreciates Staff's recommendation that the Commission approve the RFP[2]. These comments address the Staff Report generally, and more specifically Staff's recommended modifications[3].

PGE acknowledges the tremendous amount of work associated with responding to PGE's application on an expedited basis and is grateful to Staff and the other Parties for timely responding to PGE's application and Reply Comments. We are particularly gratified that PGE, Staff, the Independent Evaluator (IE), and the other Parties have found substantial common ground. Of the twenty-one primary issues identified in the Staff Report, PGE and Staff have alignment on thirteen issues[4, 5]. PGE welcomes the opportunity to revisit the two issues (of the said thirteen) requested by Staff in future planning and procurement dockets[6].

[1] April 23, 2018 memo from Staff to the Public Utility Commission relating to PGE Docket No. UM 1934 (Staff Report).
[2] Subject to certain conditions.
[3] Staff Report at page 4.
[4] Staff Report, Specific Issues 1, 3, 4, 5, 9, 11, 13, 14, 15, 16, 17, 18, 19. Staff accepted PGE's offer to perform a sensitivity analyses regarding Specific Issue 15, and stated its expectation that the issue be more transparently explained in the future.
[5] These thirteen issues include issues that Staff discussed but did not include a request to address. See Staff Report, Specific Issues 14, 16, and 18.
[6] Staff Report, Specific Issues 11 and 15. In connection with Specific Issue 15, Staff appreciated PGE's inclusion of its planning horizon sensitivities which will provide Staff and the other Parties necessary information in this RFP.

In this Response in support of its RFP, PGE addresses Staff's request for additional information on five issues[7]. In addition, PGE explains why the Commission should approve this RFP notwithstanding the remaining three issues raised by Staff[8]. PGE appreciates the work done by Staff and the other Parties to narrow the issues for Commission consideration and decision.

1. Staff's Request For Additional Information

In this section, PGE addresses the issues where Staff has requested that PGE provide additional information in this RFP.

A. Issue 2 – Firm Transmission Requirement

Staff requests that PGE explain why the potential cost savings for non-long-term firm transmission is outweighed by the reliability risks of lesser quality transmission products. Staff states that "[l]ong-term firm transmission is of course the most reliable, and of course transmission with the possibility of curtailment would be cheaper."[9] This maybe counter-intuitive, but non-long-term firm transmission products are in fact NOT cheaper than Long Term Firm (LTF) transmission.[10] BPA's rate design encourages customers to elect LTF service, in part, as it provides five years of financial certainty for the agency. BPA charges the exact same tariffed transmission rates for firm and conditional-firm transmission. As such 'transmission with the possibility of curtailment' is NOT cheaper. There is in fact no cost savings from these services when compared to LTF.[11]

PGE requires LTF transmission to both minimize risk and provide reliability to customers at reasonable costs. As discussed in PGE's Reply Comments[12], non-LTF service products are inferior and have limited availability due to the nature of the products.[13] It is not consistent with

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[7] Staff Report, Specific Issues 2, 10, 12, 20 and 21.
[8] Staff Report, Specific Issues 6, 7, and 8.
[9] Staff Report Page 6.
[10] 2018 BPA Transmission, Ancillary and Control Area Service Rate Summary https://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/FY18-19/2018%20Rate%20Schedule%20Summary.pdf
[11] If bought for a comparable length of time, short-term firm is more expensive than LTF. Short-term firm can be purchased selectively throughout the year. Daily firm, for example, is more expensive than long term firm if more than 259 days of transmission are purchased.
[12] PGE Reply Comments Section II, 1, (c)
[13] See BPA Conditional Firm Transmission Service Agreement Section 1(f) at

prudent utility practice to procure long-term resources, either by contract or ownership, without assured delivery over the life of the contract or asset.[14] Non-LTF products (including conditional-firm reassessment and short-term firm products) do not include availability assurances for more than two years. Resources relying on non-LTF transmission could be unavailable or even curtailed, i.e. undeliverable, for days or months. Such transmission conditions would limit the economic benefit of the resources, and could jeopardize PGE's reliability.

As discussed in PGE's Reply Comments[15], transmission is a capacity based product[16] and there are periods where the output of a variable resource does not use the full capacity. During these periods, the transmission customer, if it is so inclined, is able to capture value[17] by reselling such unused transmission capacity. Historically, PGE has found that LTF service includes this residual value, reducing the overall cost of customer transmission service.[18]

As discussed above, non-LTF products do not lower transmission costs and therefore it is misleading to compare the assumed cost savings of non-LTF to the consequences of inferior reliability service. As discussed above, one cannot assume that resources supported by non-LTF products are deliverable for the life of the asset[19]. PGE's LTF transmission requirement is necessary to provide customers dependable project value and reliable service at reasonable costs.

B. Issue 10 – Pseudo-Ties

Staff requests additional assurances that all bids, regardless of commercial structure, will be required or evaluated to include the same balancing costs. As discussed in our response to

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https://www.bpa.gov/transmission/Doing%20Business/bp/.../06-CF_Agreement.doc

[14] PGE also notes that other RFPs have had similar LTF requirements. See for example, El Paso Electric 2017 RFP https://www.epelectric.com/files/html/EPE_2017_All_Source_RFP.pdf, PacifiCorp 2017 RFP http://www.pacificorp.com/sup/rfps/2017-rfp.html, and Puget Sound Energy 2018 RFP https://pse.com/aboutpse/EnergySupply/Documents/Renewable_Energy_RFP_Main.pdf

[15] Reply Comments at page 4.

[16] When an entity purchases transmission, they are paying for the capacity to be able to transmit energy. Hence, the product is charged and made available on a MW capacity basis, not a MWh energy basis.

[17] PGE's Annual Update Tariff (AUT) includes a forecasting of transmission resale net revenue.

[18] For a PPA with LTF, the project owner could easily engage in a similar activity as PGE and actively manage resales to increase its revenues. The primary difference is the increased revenues will benefit the project owner, whereas PGE passes on the benefit to customers.

[19] Availability guarantee is generally limited to two years.

Specific 6 below, PGE reaffirms its commitment to require all off-system bids to include costs associated with sixty minute balancing services[20]. Furthermore, Staff's concern regarding benchmark resources submitting lower prices by relying on future balancing service elections are misplaced for reasons discussed in our response to Specific 6.

C. Issue 12 - Escalation Rate

Staff requests that PGE publish its assumed BPA transmission tariff escalation costs. PGE disclosed the assumed escalation rates related to BPA wheeling rates in the 2016 IRP Update which was filed March 8, 2018. The description of PGE's transmission cost assumptions are described in Table 7, footnote 6 of the 2016 IRP Update.[21] Specifically, tariffed transmission costs are consistent with the BP-18 rate case and escalated at inflation. PGE's RFP evaluation will apply this acknowledged IRP assumptions for all resources using BPA transmission, including the Benchmark bid.

D. Issue 20 – Prohibiting Capital Additions

Staff requests justification for the inclusion of a Form PPA provision[22], which limits increased project output through facility capital additions. PGE does not intend to limit a seller's ability to perform maintenance or upgrades at its facility. PGE includes this provision to ensure that sellers do not increase facility output, and put the increased output to PGE, after commercial operations. PGE's contract must protect customers in a falling price environment by securing the agreed upon capacity and energy output from the seller for the term of the contract. Without terms and conditions limiting capital additions or upgrades at the facility, the seller may argue that it has the right to increase production above the contract volumes and be entitled to the original PPA price for the increased output[23].

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[20] In the Final RFP, PGE will make this abundantly clear.

[21] http://edocs.puc.state.or.us/efdocs/HAO/lc66hao12513.pdf

[22] Section 3.8.6 of the Form PPA provides as follows: "Maximum Delivery Amounts. Seller shall sell and deliver, and PGE shall buy and receive, the Delivered Energy Quantity delivered pursuant to this Agreement, up to the Net Available Capacity. Seller shall not increase (i) the Facility's ability to deliver Facility Output, (ii) Nameplate Capacity, or (iii) Net Available Capacity through any means, including but not limited to replacement or modification of equipment or related infrastructure."

[23] PGE will be willing to entertain a modification of this provision provided that any obligation on PGE to buy any increased output is subject to further agreement between the parties on price and terms.

E. Issue 21 - Damage Cap

The Mutual Confidentiality Agreement[24] included in this RFP limited either party's damages to $100,000. This limitation of liability is one that PGE has agreed to with multiple counterparties in similar commercial transactions. However, in response to Staff's[25] comments, PGE will increase the damages cap to $500,000. As previously stated, a $100,000 limitation of liability in confidentiality agreements represents the current market. Limited amounts of information are exchanged between the parties during this solicitation and in any event, no party is compelled to disclose particular information under the confidentiality agreement. As such, a damage cap of $500,000 is sufficient for the potential risk.

2. Three Remaining Issues

In this section, PGE addresses the three issues where PGE disagrees with Staff's conclusions and proposed modifications, and explains why the Commission should approve this RFP.

A. Issue 6 – 15 vs 60 Minute Scheduling

PGE disagrees with Staff's recommendation that the Commission require PGE to accept 15 minute schedules from all bid types. In the Staff Report, Staff recognizes that intra-hour variability introduces costs, which will either be paid by the resource seller or resource buyer.[26] Intra-hour resource variability generally requires intra-hour response from dispatchable generating resources, and this creates costs. In PGE's Reply Comments[27], we explained that it is inappropriate and unfair to shift intra-hour costs created by third-party sellers to PGE's customers and PGE's shareholders.

The Commission should consider PGE's proposed scheduling requirements from two perspectives. First, the Commission should consider whether or not the RFP's scheduling requirements unduly advantages certain commercial structures relative to others. Second, the Commission should consider the origin of the cost when determining whether the RFP fairly allocates intra-hour scheduling costs to the party responsible for introducing the intra-hour costs.

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[24] Appendix F, Section 12(b), filed with the Final Draft 2018 RFP.
[25] NIPPC also made some comments about the cap.
[26] Staff Report, page 9.
[27] Reply Comments at page 11.

First, PGE's proposed scheduling requirements do not advantage a subset of bids. PGE's RFP requires all off-system bids, regardless of commercial structure, be delivered to PGE using hourly schedules. As such all off-system bids will be required to include tariffed integration costs and will be evaluated in a consistent manner. Thus the RFP requirement creates no competitive advantage between different commercial structures.

It is possible that Staff is concerned that a competitive advantage may be introduced if at a later date PGE were to reduce utility owned integration costs by electing intra-hour scheduling or full self-integration. When discussing pseudo-ties in Specific Issue 10, Staff articulates its concern "that if PGE can pseudo-tie any self-built resource, [the Benchmark bid] can offer a lower price knowing those balancing costs will soon be replaced with lower balancing costs."[28] Staff's concern is misplaced, as Oregon's cost of service regulation does not incent utility owned bids to offer lower bid prices in anticipation of electing cheaper balancing services at a later date. If an off-system, utility owned resource is selected, BPA would study the possibility to pseudo-tie the resource and the cost and benefit of executing a pseudo-tie or intra-hour scheduling would be examined by PGE. If such actions were deemed prudent and implemented, any savings resulting from the decision would be recognized in PGE's annual power cost filing and accrue to customers.

Secondly, PGE's proposed scheduling requirements encourage the total costs of resources to be reflected in bid pricing and require the party responsible for introducing balancing costs to bear such costs. Therefore, PGE requires the project owner to be responsible for managing intra-hour scheduling costs. PGE's participation in the Western EIM requires PGE to submit hourly base schedules to the market operator. Should PGE be compelled to accept variable, third-party intra-hour deliveries PGE will be assessed imbalance settlements. Without agreement with the counterparty, PGE will be unable to assign these costs to the third party project owner responsible for creating the intra-hour imbalance. Under the current regulatory construct, forecasted third-party imbalance settlements are not included in PGE's forecasted power costs. As such, PGE's shareholders would, unfairly, be held responsible to pay for third-party imbalance costs. A fair, reasonable and cost-effective remedy to this market mechanism is to require third-party bids to deliver 60 minute schedules. This requirement would prevent the

[28] Staff Report at page 11.

creation of intra-hour imbalances relative to PGE's base schedule, thereby treating project owner and project purchaser fairly.

It is undisputed that the owner of a variable energy resource introduces intra-hour variability thereby creating costs. Staff's recommendation to allow for 15 minute schedules because PGE's customers have already invested in the assets necessary to accommodate intra-hour deliveries is flawed for several reasons. Staff assumes that customer investments in PGE's generating assets, specifically Port Westward II, enable PGE to pay the cost associated with balancing intermittent resources.[29] This argument fails to recognize two important facts: (1) the presence of flexible capacity resources in PGE's portfolio does not allow for the limitless and costless balancing of infinite intermittent resources[30], and (2) under the present operating paradigm, PGE's shareholders, not customers, are responsible for EIM intra-hour imbalance settlements introduced through 15 minute schedules.

PGE's generating portfolio is not designed for the unlimited and costless integration of intermittent resources. PGE's flexible capacity resources, including Port Westward II, were acquired to meet PGE's peak capacity needs in addition to PGE's flexible capacity needs.[31] Were PGE to be compelled to accept 15 minute schedules from a third party, the operation of PGE's capacity resources would be adversely affected increasing PGE's total net variable power costs. The costs of this action would be borne by PGE and its customers.

B. Issue 7 – Specified Energy

Staff recommends that PGE alter its preferred contract terms and conditions regarding Specified Energy. PGE disagrees with Staff's recommendation for two important reasons. First, PGE's Specified Energy terms and conditions are increasingly in use in the wholesale energy market to assign monthly forecast error costs to project owners, the party most able to mitigate the risk, in a manner comparable to the costs borne by PGE's shareholders for utility owned resources. Secondly, the RFP process allows PGE to introduce preferred terms and conditions in its form contracts. Bidders are welcome to redline the form agreements and provide alternative

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[29] Staff Report at page 9.
[30] PGE's rates currently reflect the fixed costs of Port Westward II, and the forecasted variable costs associated with that facility. Integration of additional variable energy resources will increase variable costs on PGE's system and for Port Westward II.
[31] Portland General Electric 2013 IRP, Chapter 5.

terms and conditions. Indeed, as discussed below, a bidder's ability to redline form agreements is provided for in the Commission's Competitive Bidding Guidelines[32]. It is premature, and unfair, to require PGE to negotiate with itself by altering its preferred terms and conditions before negotiating with third parties who may have unique proposals. This is particularly unfair since PGE has demonstrated why these terms and conditions are reasonable and fair and appropriately assign costs and risks while protecting customers.

Staff argues that PGE's Specified Energy terms and conditions present a competitive imbalance between PPA and utility owned bids.[33] PGE disagrees. Specifically, when identifying why PGE's preferred terms and conditions should be altered, Staff relies upon a comparison of over-production benefit and under-production costs between different commercial structures:

> "Over-production benefits are roughly equivalent between self-build and PPA, as until wide-scale adoption of electricity storage, both will sell excess production at market rates. However, there is a significant difference for under-production: PPAs must increase their price to account for this risk, while the self-build option simply passes this increased cost (of under-production) onto ratepayers."[34]

Staff's argument relies on the premise that PGE shareholders are not exposed to the costs of variable resource under-production, suggesting these costs can simply be transferred to customers. In fact, the regulatory construct assigns the cost of under production to PGE's shareholders, not customers. PGE's net variable power costs (NVPC) are established on a forecasted basis and assume a particular quantity of monthly generation from resources including PGE owned and third party owned variable energy resources. Variable resources will undoubtedly generate at quantities that differ from NVPC forecasts, and should the resources generate at levels below forecast, PGE is responsible to replace those deliveries with power from its dispatchable generating resources or from power purchases in the wholesale market, or both. The costs of those actions are borne by PGE shareholders unless the costs are high enough to trigger the OPUC's Power Cost Adjustment Mechanism provisions.

[32] See Order 14-149 (Commission Guidelines).
[33] Staff Report at page 10.
[34] Staff Report at page 9 (Internal footnote omitted).

PGE has a history of documenting the costs borne by shareholders due to the under-production of PGE's wind resources. For example, in PGE's 2017 Annual Report released to the investment community, PGE stated:

> "PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company's thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations…[35]
>
> Energy expected to be received from wind generating resources (Biglow Canyon and Tucannon River) is projected annually in the AUT based on historical generation. Any excess in wind generation from that projected in the AUT generally displaces power from higher-cost sources, while any shortfall is generally replaced with power from higher-cost sources. Energy received from wind generating resources fell short of that projected in PGE's AUT by 18% in 2017, 7% in 2016, and 15% in 2015. Wind generation forecasts are developed using a 5-year rolling average of historical wind levels or forecast studies when historical data is not available. As a result of the generation shortfalls, production tax credits have not materialized to the extent contemplated in the Company's prices."[36]

As is evident from the above, PGE shareholders are at risk for the costs related to under generation of utility owned resources. It would be unfair and inappropriate[37] to require PGE to abandon its preferred terms and conditions that would mitigate the risk to PGE's shareholders for the under generation of third party owned resources. Staff suggests that the Specified Energy terms be removed or that the Commission make PGE responsible to bear similar risks for utility owned projects.[38] Removing the Specified Energy terms will only compound the risk as PGE's shareholders are already at risks for under generation for owned projects. Fairness requires third-party owned resources also be held accountable for these costs.

[35] 2017 Annual Report Page 26.
[36] 2017 Annual Report Page 40.
[37] As it will provide an incentive for a bidder not to reflect the true costs of its project in its bid.
[38] Staff Report at page 4.

C. Issue 8 – Redlines Diminish Scores

This RFP complies with the Commission Guidelines. As required by Commission Guideline 6, the RFP permits bidders to propose alternative terms and conditions to those identified in the form agreements as a first step toward negotiating mutually agreeable final contract terms. PGE's non-price scoring rubric includes a question which assesses the bidder's conformance to the standard form contracts that were attached to the RFP. The Staff Report suggests that PGE's RFP design should not allow for non-price adjustments should bidders choose to propose less protective terms and conditions.[39] PGE believes that Staff's articulated position is inconsistent with the Commission Guidelines. Commission Guideline 9(a) clearly states:

> The non-price score should be based on resource characteristics identified in the utility's acknowledged IRP Action Plan… and conformance to the standard form contracts attached to the RFP.[40]

This Commission Guideline specifically states that non-price scoring should reflect bidders' conformance with the standard form contracts provided. Contract terms and conditions can be of equal importance to contract price, and should therefore be assessed in non-price scoring. We believe that a closer read and further consideration of the Commission Guidelines addresses the concern expressed by Staff.

Finally, contract price and contract risk are linked in standard bilateral negotiations. Not allowing PGE to negotiate the terms of its contract, as Staff's proposal implies, would break the relationship between contract price and contract risk. Generally, if risk is assumed by a buyer, a lower price is agreed to with the seller. If risk is assumed by a seller, a higher price is agreed to with the buyer. By not allowing PGE to score a shift in risk (which is exhibited by redlines to the PPA), Staff's proposal would artificially distort price scoring. In other words, a bid with a lower price with a PPA that shift significant amounts of risk to PGE and its customers could score higher than a bid with a higher price but no shift in risk to PGE and its customers. Selection of least-cost and least-risk resources requires PGE to evaluate the impact of redlines (risk shifts) to the form agreements.

[39] Staff Report at page 10.
[40] Commission Guideline #9 (a) (Order No. 14-149)

CONCLUSION

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 acknowledged in the 2016 IRP Addendum Order No. 18-044, PGE intends to acquire 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 tax credits while replacing a portion of PGE's capacity needs with clean energy following the cessation of coal fired operations at the Boardman coal plant. Throughout this RFP process, PGE has made changes in response to the IE, Staff and the other Parties' feedback. The RFP as designed is fair and transparent, and complies with the Commission Guidelines. Staff and the IE[41] recommend approval of this RFP by the Commission. For the reasons stated above, PGE respectfully request that the Commission approve this RFP as proposed with the changes that PGE has discussed in this response[42].

[41] Independent Evaluator's April 6, 2018 Assessment of the 2018 RFP.
[42] And the changes PGE committed to make in response to the IE's Initial Assessment.

Dated this 30th day of April, 2018.

Respectfully submitted,

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