BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1934

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2018 Request for Proposals for Renewable Resources.	Opening Comments

Introduction

Following are Staff's initial comments and recommendations on Portland General Electric's (PGE or Company) Request for Proposals (RFP) for 100MWa of renewable resources. These comments are preliminary and focus on the competitiveness of the RFP and the Commission's guidelines for competitive bidding. Before issuing Staff's final recommendations in its Staff Report to be filed on April 23, 2018, Staff will further review the company's draft RFP, responses to any information requests, and stakeholder comments.

In general, Staff is concerned that PGE's RFP might fail to uphold the Commission's guidelines of being transparent, fair, and nondiscriminatory, and as such, Staff will be investigating a number of issues described below. PGE must justify how their RFP encourages competition and appropriately evaluates all submitted bids, both in information responses as well as its April 13, 2018 reply comments. Staff looks forward to working with PGE, stakeholders, and the Independent Evaluator (IE) to develop the best possible RFP. Below are the issues which have raised the most concern for Staff, all of which will receive further scrutiny going forward.

Analysis

Price Versus Non-Price Weighting

PGE proposes a 60/40 weighting between price and non-price criteria when evaluating individual bids. This 60/40 split has been used for many recent PGE RFPs, with a 50/50 division used in an earlier RFP.[1] A 100/0 split would provide the simplest evaluation and most transparency, as bids could simply be sorted by the prices proposed. However, PGE states that the non-price portion of the score evaluates the implicit risks not captured in the price score associated with each bid.[2] When directly asked to justify the magnitude of the price/non-price weighting, the Company simply chose to explain the purpose of a non-price score, and state that the Company believes that it is reasonable.[3]

This response by PGE is insufficient because it does not explain or justify why this particular weighting is appropriate in this RFP, even when acknowledging the established record of the 60/40 split between price and non-price factors. An important component of this process is transparency, which appears to come at a tradeoff with non-price weighting. Accounting for risk is of course appropriate, and there is likely an optimal split, however, PGE has not yet convinced Staff that it should be 60/40. In PacifiCorp's recent RFP, the price/non-price split was 80/20, with no apparent increase in risk.[4] PGE's proposed RFP, as well as information responses, does not sufficiently justify why such a large non-price weighting is appropriate.

In addition, one potentially useful way to evaluate the reasonableness of this weighting would be to conduct a sensitivity analysis. For example, after the scores are calculated, how much would the group of winning bids change if the price split were different? If they are significantly different, then the final results would be thought to be relatively sensitive to that weighting; a stable set of winners from different splits would be considered relatively insensitive to that change. As written, this RFP includes no plans to examine this split.[5] Staff is concerned that this omission will obfuscate important information about this RFP, and will examine this issue going forward.

Transmission Cost Risk

RFP and bid evaluation processes are designed such that PGE would be completely indifferent between identical projects with different ownership options. Whether utility-owned, build- -transfer-agreements (BTA), power purchasing agreement (PPA), or some hybrid approach, the utility should evaluate each proposal on its established price and non-price criteria to identify the highest-value projects. Staff is concerned that the differences in transmission costs between ownership types could play a disproportionate role in the selection process.

In this RFP, PGE requires bids to include the costs of 20-years' worth of guaranteed (or firm) transmission to PGE's service territory, which represents a tangible portion of each project's total costs. This, of course, directly influences the prices individual bids can offer. Adding to these is the uncertainty faced when estimating transmission costs in the future. Each bid submits a fixed price for PGE to pay for the electricity, but in the event

[1] PGE's Response to Staff IRs #2 & 3.
[2] PGE's Response to Staff IRs #1.
[3] PGE's Response to Staff IRs #1.
[4] *See* UM 1845.
[5] PGE's Response to Staff IRs #4.

of a transmission cost increase, an independent bid will receive less in compensation. As the likelihood of rising transmission cost increases, independent generators must also increase their bid price to account for the additional risk. However, utility-owned projects do not face the same risks; they can simply pass the cost on to ratepayers through a power adjustment clause. Staff flags this concern: that without pricing the same levels of risk into their bid, utility-owned projects will appear cheaper, when in reality they are just passing that same risk to ratepayers rather than pricing it in their bid.

Further, it is not clear to Staff that utility-owned projects will pay the same costs for delivery as an independent bid. In addition to the transmission costs, to cross BPA's Balancing Authority Area (BAA), a wind project must also pay ancillary services related to regulating, following, and imbalance charges.[6] However, PGE recently implemented the use of a pseudo-tie[7] through BPA's BAA for its wind resources at Bigalow Canyon and Tucannon River, allowing it to avoid paying the otherwise required ancillary services. Once this resource is connected to PGE's BAA, it can be part of the Energy Imbalance Market (EIM), which should lower the ancillary service cost. Given the possibility of dynamic transferring combined with the attractiveness of the EIM, Staff is seeking clarification as to whether the benchmark bid provides a reasonable comparison.

Firm Transmission Requirement

Requiring individual bids to have firm transmission for twenty years is concerning to Staff, as it could be an unnecessarily high requirement for non-utility-owned bids. PGE's justification is that they want the guarantee that electrons generated by distant producers are able to be shipped to their balancing area. However, this leaves little room for any cost considerations surrounding this requirement, which Staff feels should be explored.

For example, consider two hypothetical bids, A & B, both proposing to build a 20MW wind facility. Bid A secures firm transmission for 20 years, and offers a total price of $50/MWh. Bid B only secures firm transmission for 15MW and requires non-firm transmission for the rest, but offers a total price of $5/MWh. As currently written, only Bid A would be considered in this RFP, even though the negative aspect of Bid B (lower reliability) might be outweighed by its benefit (affordability). This is not to say that firm transmission does not provide a benefit: if the price of both bids were equal, Bid A would clearly be preferable to both PGE and its ratepayers. However, this firm-transmission requirement of the current RFP values risk above all else, and fails to incorporate cost. Staff believes there should be some accounting of the trade-off between the two with respect to transmission in the RFP.

[6] *See* BPA 2018 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2018–2019).
[7] An agreement between PGE and BPA where generation at those wind facilities is automatically transferred to PGE without balancing. Under the pseudo-tie, PGE only pays transmission costs, and not the ancillary costs it otherwise would be required to purchase.

EIM Participation

PGE having access to the EIM market also raises concerns about the competitive tilt with the compensation of PPAs in this RFP. To meet specified energy requirements, a PPA assigns a price PGE will pay for each 12x24x2 block.[8] As renewables are intermittent, the likelihood that the specified quantity is not perfectly met is high. Consider two time periods: in the first, the generator produces less, say 80 percent of the agreed-upon quantity, and receive only 80 percent of the price. However, in the second, the generator produces more, say 120 percent of their contracted amount, and the PPA only pays the undelivered Mid-C spot price for that additional 20 percent, which might not cover all costs missed from the first time period. While this is true for the benchmark bid as well, PGE's access to the EIM mitigates this risk, as instead of this Mid-C price, it could sell at potentially higher wholesale market prices. If a PPA were identical in all other ways to the benchmark, it would be forced to offer higher prices to reflect this difference, tilting the competitive balance between identical projects towards utility ownership. In section 3.8.9, PGE retains the discretion to restrict bids joining any organized market, potentially solidifying this advantage.[9] This is especially concerning to Staff, and will require further clarification as to whether these requirements represent a competitive environment for resource procurement.

60 Minute Schedule

For resources outside of PGE's BAA, PGE requires bids to delivered firm for each 60-minute scheduling interval.[10] The only acceptable excuse for failure to deliver is force majeure. This is difficult for renewables, as their intermittency requires significant ancillary services over the entire hour to balance their delivery. However, this difficulty is alleviated as the schedule duration decreases. Accordingly, BPA began in 2014 to schedule the buying, selling, and transmitting of energy at 15 minute increments. Staff is investigating whether this 60-minute scheduling requirement is appropriate given the intra-hour scheduling availability in BPA's BAA.

Montana

This Commission specifically ordered that in the RFP process, PGE "discuss aspects of RFP design and scoring that impact the treatment of Montana wind resources."[11] A significant constraint is the lack of available transmission capacity from Montana to our region, however this 100MWa renewable RFP is not sufficient to shoulder the financial burden to alleviate this constraint.

Renewable Diversity

Wind energy generated in Montana presents a unique opportunity for PGE, as having a diverse set of renewable generation options lessens the dependency on PGE's BAA for

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[8] Representing light and heavy loads for every hour in each month.
[9] Proposed RFP Appendix A at 37.
[10] Section 6.1.7, PGE RFP at 20.
[11] Docket No. LC 66, Order No. 18-044 at 1.

specific weather conditions, lowering integration costs. It produces at times when generation facilities in the Columbia Gorge are idle, and vice versa. Accordingly, the value associated with the production from a non-Gorge wind facility is higher for PGE than those that would be developed in the Gorge. Staff expects PGE's RFP to include exploration of this diversity value from renewable generation with different generation profiles.

Credit Requirements

The credit requirements presented in this RFP appear unnecessarily high, and will limit the number and quality of bids submitted. PGE is requiring five years mark-to-market post COD collateral, something it has never done before (earlier RFPs have required three years' worth). PGE explains that this is an attempt at minimizing risk of a counterparty defaulting; this certainly represents a benefit to PGE and its ratepayers.[12] However PGE ignores the cost of this additional requirement: a potential reduction in the number and quality of bids. In its information response, PGE in no way attempts to weight the costs versus the benefits of the change. Therefore Staff will continue asking PGE to explain and justify this increase.

Negotiated Clauses

All bidders are required to propose alternative terms and conditions to all applicable highlighted stipulations in their proposal.[13] However, under the Performance Certainty section of the non-price scoring criteria presented in Appendix H, both the Liability Cap and Default & Termination categories award the full six points possible to bids in which "*All highlighted terms* conform to contract form and present low risk to schedule, performance or cost, and *additional terms are included that lowers Company risk*."[14] This appears onerous, as to receive any points in these sections at all, most of PGE's terms must be accepted. Staff is working to determine whether these are sections reasonable.

PURPA Clause

Staff is unsure of the reasonableness of Section 6.1.8's PURPA requirements, which mandate that a project in current PURPA negotiations cannot bid into this program. The RFP's other PURPA related section, 5.8, mandates that any seller which terminates its contract due to default waives its ability to use PURPA with PGE. This makes sense to Staff, as there cannot be a financial incentive to terminate agreements made in this RFP. However, Staff does not understand why, prior to entering into any agreement with PGE, a project would be limited to negotiating under PURPA. Staff will investigate this matter further.

[12] PGE's Response to Staff IRs #9.
[13] Initial RFP at 16.
[14] Initial RFP at 1219 (emphasis added).

IRP Compliance

A condition of the acknowledgment of PGE's 2016 IRP was that PGE in this RFP would "provide updates to the Company's energy, capacity, and RPS needs".[15] On March 28, 2018, PGE submitted an additional appendix which on the surface appears to have satisfied this condition, however, Staff has not fully reviewed this document. Staff will have an opinion regarding this compliance when it files its final comments on the matter.

Conclusion

In a number of ways set forth in these comments, Staff has real concerns that PGE's RFP does not uphold the competitive goals set forth by the Commission in its Competitive Bidding Guidelines. It is the responsibility of PGE to explain to Staff, stakeholders, and the IE how their proposed RFP encourages competition while fairly, transparently, and in a nondiscriminatory fashion, evaluates all submitted bids. Thus far, PGE has not convinced Staff about the reasonableness of many important components of this RFP. Staff will continue to work cooperatively with PGE through the remainder of this process to evaluate this proposal under the accelerated timeline of this RFP.

This concludes Staff's comments.

Dated at Salem, Oregon, this 30th day of March, 2018.

Seth Wiggins
Senior Utility Analyst
Energy Resources and Planning Division

[15] Docket No. LC 66, Order No. 18-044 at 1.

March 26, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Jimmy Lindsay
Project Manager, Resource Strategy

PORTLAND GENERAL ELECTRIC
UM 1934
PGE Response to OPUC Data Request No. 001
Dated March 21, 2018

Request:

Please explain the justification of weighting bid price/non-price scores at 60/40 percent.

Response:

PGE's proposed price and non-price weighting balances project cost and project risks to identify least cost, least risk resources for customers. A 60 percent price score weighting reflects PGE's intent to prioritize resources of least cost and greatest value to customers. A 40 percent non-price weighting reflects PGE's intent to also appropriately recognize least risk resources for customers.

Consistent with the Oregon Public Utility Commission's Order 91-1383 in UM 316[1], PGE has regularly utilized a 40% non-price score allocation to reflect the implicit risks that are not captured in the price score.[2] PGE believes that it is reasonable and appropriate to balance price and non-price scoring factors with a 60/40 weighting in the 2018 Renewable RFP.

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[1] In UM 316 Staff recommended that non-price factors be weighted 30%-50% to appropriately address various risks factors associated with projects.
[2] See PGE's response to Staff's DR 002 and DR003.

March 26, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Jimmy Lindsay
Project Manager, Resource Strategy

PORTLAND GENERAL ELECTRIC
UM 1934
PGE Response to OPUC Data Request No. 002
Dated March 21, 2018

Request:

Please provide all previous PGE RFPs that have used similar 60/40 splits between price and non-price scores, highlighting relevant pages.

Response:

PGE objects to this request as it is unduly burdensome to identify and characterize all PGE RFPs. Without waiving this objection, PGE identifies below all RFPs for major resources procured under the competitive bidding guidelines first adopted by the Commission in UM 316.

- PGE's 2016 Renewable RFP used a 60/40 price non-price scoring weighting as identified on page 20.
- PGE's 2012 Power Supply Resources RFP used a 60/40 price non-price scoring weighting as identified on page 28.
- PGE's 2012 Renewable RFP used a 60/40 price non-price scoring weighting as identified on page 20.
- PGE's 2008 Renewable RFP used a 60/40 price non-price scoring weighting as identified on page 18.
- PGE's 2004 Power Supply Resources RFP used a 60/40 price non-price scoring weighting as identified on page 23.

March 26, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Jimmy Lindsay
Project Manager, Resource Strategy

PORTLAND GENERAL ELECTRIC
UM 1934
PGE Response to OPUC Data Request No. 003
Dated March 21, 2018

<u>Request:</u>

Please provide all previous PGE RFPs that have different splits between price and non-price scores, highlighting relevant pages.

<u>Response:</u>

PGE objects to this request as it is unduly burdensome to identify and characterize all PGE RFPs. Without waiving this objection, PGE identifies below all RFPs for major resources procured under the competitive bidding guidelines first adopted by the Commission in UM 316 that do not use a 60/40 price and non-price weighting.

- PGE's 1993 RFP used a 50/50 price non-price scoring weighting as identified on page 14.

March 26, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Jimmy Lindsay
Project Manager, Resource Strategy

PORTLAND GENERAL ELECTRIC
UM 1934
PGE Response to OPUC Data Request No. 004
Dated March 21, 2018

Request:

Is the 60/40 percent split between price and non-price scores meant to be fixed throughout the RFP evaluation process? Can the parameters of the price score be modified in response to the bids received?

Response:

The 60/40 price non-price scoring weighting is designed to remain as proposed throughout the evaluation. PGE does not propose to conduct price and non-price weighting sensitivities within the RFP evaluation.

March 26, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Jimmy Lindsay
Project Manager, Resource Strategy

PORTLAND GENERAL ELECTRIC
UM 1934
PGE Response to OPUC Data Request No. 009
Dated March 21, 2018

Request:

For PPA bids, why is post-COD collateral based on five years of mark to market exposure? Please identify all previous PGE RFPs that included this requirement.

Response:

PGE's previous RFPs have not required five years mark-to-market post-COD collateral. Both the 2012 Renewable RFP and the proposed 2016 Renewable RFP required three years mark-to-market post-COD collateral. PGE has extended the post-COD collateral period for two reasons.

First, the majority of PGE's long-term agreements are executed under enabling agreements[1] and limited to a maximum term of five years per PGE's Energy Risk Management Policies and Procedures[2]. For five-year agreements, collateral is calculated for the entire five year term.

Second, as the renewable resource market becomes more competitive, PGE would like to minimize the risk of the counterparty defaulting on the PPA to pursue more attractive pricing with another party.

[1] Primary long-term enabling agreements used by PGE are: 1) ISDA – International Swaps & Derivatives Association, Master Agreement for derivatives transactions, and 2) NAESB – North American Energy Standards Board, Base Agreement for Sale and Purchase of Natural Gas.
[2] Per PGE's Energy Risk Management Policies and Procedures, transactions longer than five years require additional management review and approval. Agreements longer than five years may include unique terms and conditions.

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Attachment 002-A, Attachment 002-B, Attachment 002-C, Attachment 002-D, Attachment 002-E

Provided in Electronic Format only