ITEM NO. 2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: MAY 8, 2018

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** **Upon Approval**

DATE: April 23, 2018

TO: Public Utility Commission

FROM: Seth Wiggins SW

THROUGH: Jason Eisdorfer and JP Batmale JE JPB

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1934) Portland General Electric Renewable Request for Proposal

STAFF RECOMMENDATION:

Staff recommends that the Commission approve Portland General Electric's (PGE or Company) Final Draft 2018 Request for Proposals (RFP) for Renewable Resources subject to the conditions described on page 4 of this Staff Report.

DISCUSSION:

Issue

Whether the Commission should approve or deny PGE's petition for approval of PGE's Final Draft 2018 Request for Proposals for Renewable Resources.

Applicable Rule or Law

The Commission's Competitive Bidding Guidelines were first established in Docket No. UM 1182, Order No. 06-446. Subsequently, the Commission has amended the Guidelines four times, most recently in Order No. 14-449, and a complete set of the Guidelines is provided as Appendix A to that order. Generally, the Guidelines require issuance of a Request for Proposals in compliance with the Guidelines for all Major Resource Acquisitions (duration greater than five years and quantities greater than 100 MW) and certain multiple small resource acquisitions that qualify for treatment as a Major Resource Acquisition.

Per Guideline 5, an independent evaluator (IE) must be used by the utility to help ensure all offers are treated fairly. An IE was approved by the Commission in UM 1834 in Order No. 17-226.

Under Guideline 6:

> The utility will prepare a draft RFP and provide the draft to all parties and interested persons in the utility's most recent general rate case, RFP and IRP dockets. The utility must conduct bidder and stakeholder workshops on the draft RFP. The utility will then submit a final draft RFP to the Commission for approval, as described in Guideline 7 [ ]. The draft RFPs must set forth any minimum bidder requirements for credit and capability, along with bid evaluation and scoring criteria. The utility may set a minimum resource size, but Qualifying Facilities larger than 10 MW must be allowed to participate. The final draft submitted to the Commission must also include the standard form contracts. However, the utility must allow bidders to negotiate mutually agreeable final contract terms that are different from ones in the standard form contracts. The utility will consult with the IE in preparing the RFPs, and the IE will submit its assessment of the final draft RFP to the Commission when the utility files for RFP approval.

The specifics for bid scoring criteria and bid evaluation are set forth in Guidelines 8 and 9. Of note are provisions in Guideline 9 that specify:

> [P]rice score should be calculated as the ratio of the bid's projected total cost per megawatt-hour to forward market prices using real-levelized or annuity methods. The non-price score should be based on resource characteristics identified in the utility's acknowledged IRP Action Plan (e.g., dispatch flexibility, resource term, portfolio diversity, etc.) and conformance to the standard form contracts attached to the RFP.

When a utility files a final draft RFP for approval, public comment shall be solicited per Guideline 7. Guideline 7 further provides that the Commission will consider the following when making its determination on whether or not to approve the utility's final draft RFP:

> (1) The alignment of the utility's RFP with its acknowledged IRP;
> (2) Whether the RFP satisfies the Competitive Bidding Guidelines; and
> (3) The overall fairness of the utility's proposed bidding process.[1]

[1] Order No. 14-149, Appendix A at 2 (Guideline 7).

Further, Guideline 7 explains that the Commission may approve the RFP with any conditions and modifications deemed necessary.

Analysis

Background
This RFP was originally conceived from PGE's 2016 IRP, where the Commission acknowledged a future need for renewable energy credits (RECs) to comply with increasing renewable portfolio standard (RPS) mandates, as well as capacity deficiency beginning in 2021.[2] In Order No. 18-044 the Company's revised action item to acquire 100 MWa of renewable energy resources was approved as part of PGE's Integrated Resource Plan (IRP). Also, motivating PGE's pursuit of renewable energy is the planned termination of the federal production tax credit (PTC), which provides financial subsidies to wind generators.

After setting the docket's schedule in mid-March, Staff filed its initial comments on March 30th. These were joined by comments from a variety of stakeholders: the Northwest Independent Power Producer Coalition (NIPPC), Renewable Northwest (RNW), the Alliance of Western Energy Consumers (AWEC, formally ICNU and NWIGU), and the Community Renewable Energy Association (CREA).

After these public comments were made, the Independent Examiner (IE), a role performed by Bates White Economic Consulting, filed its assessment on April 6, and PGE filed Reply Comments addressing the issues raised by Staff, stakeholders, and the IE on April 13. This accelerated schedule is due in large part to the tight timeline of the expiring PTC, which exacerbates many of the issues discussed below. This report represents Staff's final recommendation on PGE's final draft RFP and includes summaries of stakeholder and PGE comments.

PGE Compliance with Review Criteria
As discussed in the Applicable Law section, the Commission's review of a final draft RFP focuses on:

(1) The alignment of the utility's RFP with its acknowledged IRP;
(2) Whether the RFP satisfies the Competitive Bidding Guidelines; and
(3) The overall fairness of the utility's proposed bidding process.[3]

Staff finds that #1 has been satisfied and #2 has been generally satisfied. Staff's primary area of concern centers around #3. A number of stakeholders have strong

[2] Order No. 18-044.
[3] Order No. 14-149, Appendix A at 2 (Guideline 7).

opinions as to whether a third-party owned bidder, identical in all other respects, would have the same likelihood of making the Shortlist as a utility-owned option based on the design of this RFP. The issue's complexity comes from the two main sources: the intermittency of renewable generation, and that most bids will be located within a Balancing Authority Area (BAA) outside of PGE's (most likely within Bonneville Power Administration's (BPA) BAA. Creating an agreement between an independent generator (a power-purchase agreement, or PPA) and PGE must address each of these challenges.

Staff recommends the Commission approve PGE's final draft RFP subject to specific conditions and modifications. These modifications would help increase the competitiveness of the RFP. Staff recommends the following modifications:

- Either relax long-term firm transmission requirements or justify why they are necessary despite the associated cost savings;
- Allow for intra-hour scheduling;
- Either remove damages associated with missing Specific Energy targets or modify the benchmark bid to face similar risk;
- Remove redline penalties;
- Address competitive imbalance created by the possibility of dynamically transferring PGE generation;
- Publish benchmark bid balancing cost escalation rate; and
- Significantly increase the damage cap.

Specific Issues
The remainder of this Staff Report highlights the 21 most salient issues raised by Staff and stakeholders, and PGE's responses to those issues, in this docket. With some issues, there exists significant overlap between stakeholders. These issues are displayed below in Table 1, ordered by number of parties which raised the concern (denoted by an 'x').

Table 1: Main Concerns Highlighted by Stakeholders

	Issue	Staff	NIPPC	RNW	AWEC	CREA	IE
1	Benchmark Bid Transmission	x	x	x	x	x	x
2	Firm Transmission Overly Restrictive	x	x	x	x	x	x
3	QF Participation	x	x	x	x	x	x
4	Transmission Acquisition Process		x	x	x	x	x
5	PGE's Excess Transmission Rights		x	x	x	x	
6	15 vs 60 Minute Scheduling	x		x		x	x
7	Specified Energy	x	x	x			x
8	Redlines Diminish Score	x	x	x			
9	Conditional-Firm Bridge		x	x			x
10	Pseudo-ties	x	x			x	
11	Price vs Non-Price Split (60/40)	x	x				x
12	Escalation Rate	x	x				
13	Interconnection Study Agreements		x	x			x
14	South of Allston Constraint		x	x			
15	NPVRR Duration / Generic Fill		x	x			
16	Montana Wind	x		x			
17	Permitting as Threshold Obligation						x
18	PPA PTC Requirement		x				
19	COD Extended				x		
20	Prohibiting Capital Additions		x				
21	Damage Cap		x				

A number of points: Some of these concerns were raised by every involved party, others only by one. NIPPC raised the most issues, and the IE responded to only a subset of the issues raised. The impact of an individual issue on the fairness of the RFP likely varies significantly, however, it is difficult to determine this *ex-ante.*[4]

<u>*1). Benchmark Bid Transmission Requirement*</u>

Briefly: Whether the benchmark bid faces the same transmission requirements as any potential third-party bid.

[4] Thus it's possible a critical issue might have only been raised once, while many could comment of a minor issue.

This issue was raised by all stakeholders (NIPCC, RNW, AWEC, CREA), by Staff's initial comments, and by the IE.

PGE's Response: In its reply comments, PGE clarified that the benchmark bid will face the same requirements as any other bid.

Staff's Assessment: PGE's response is sufficient, and alleviates many concerns held by stakeholders.

2). Firm Transmission Requirement

Briefly: Whether it is appropriate for PGE to mandate that all bids secure 20-years' worth of firm transmission for this RFP. There are a number of transmission services that could be procured at lower cost, but which come at lower reliability.

This issue was raised by all stakeholders (NIPCC, RNW, AWEC, CREA) and in Staff's initial comments. The IE stated that requiring long-term firm is appropriate.

PGE's Response: In its reply comments, PGE reiterated its position that long-term firm transmission is required for reliable service.[5] They highlight that transmission services less than long-term firm can be curtailed in BPA's BAA, the congestion on which is only increasing.

Staff's Assessment: As noted in Staff's initial comments, there is a trade-off in this issue between cost and risk. Long-term firm transmission is of course the most reliable, and of course transmission with the possibility of curtailment would be cheaper. Thus far, PGE, Staff, and stakeholders have simply identified this trade-off: PGE is concerned about reliability, stakeholders are worried about cost.[6] Neither have sufficiently convinced Staff why their position strictly overrides the other.

The IE stated that requiring long-term firm transmission is appropriate, but did not mention this trade-off. PAC's recent RFP's requirement of long-term firm transmission[7]

---

[5] See section 1(c): Long-term firm transmission is required for reliable service. Pg. 7.
[6] Costs either to ratepayers facing higher rates or PPA's forced to offer more expensive bids, decreasing their likelihood of reaching the shortlist.
[7] From PAC's RFP: As noted above, the minimum eligibility requirements for bidders include the provision of evidence that the proposed project has either: (1) requested a direct interconnection with PacifiCorp's transmission system and executed an interconnection feasibility study agreement with PacifiCorp's transmission function; or (2) requested interconnection with a third party's system, executed an interconnection feasibility study agreement with the third party transmission provider, and requested long-term, firm third-party transmission service from the resource's point of interconnection with the third party's system to the proposed point of delivery on PacifiCorp's system.

received far less push back from stakeholders, though admittedly PAC has far less congestion on its system.

One important consideration to this question is the original intent of the RFP. While PGE is deficient in capacity beginning in 2021, the purpose of this RFP is for energy, capacity and future RPS needs. Additionally, this RFP allows PGE to take advantage of the expiring PTC to achieve RPS compliance, as noted in PGE's used of a 'glide path'. However, Staff does feel that there is an extra burden placed on PGE to explain why 20 years' worth of firm transmission is the only way to achieve reliability. This RFP, at a minimum, needs to explain its rigidly on long-term firm transmission, specifically addressing the potential cost savings rate payers could realize under less strict requirements.

3). QF Participation

Briefly: PGE's initial application prevented bids from QFs with existing contracts. Further, PGE's draft PPA asked successful bids to forfeit their right to engage in PURPA contracts in the future if they exit their contract.

This issue (in variety of fashions) was raised by all stakeholders (NIPCC, RNW, AWEC, CREA), in Staff's initial comments, and by the IE.

PGE's Response: In its Reply Comments, PGE modified the RFP to enable QFs with existing contracts to participate, while maintaining the position that PPA's waive their right to future PURPA contracts.

Staff's Assessment: PGE's response is the optimal solution. There is little harm to have QFs with existing contracts bid into the RFP. On the other hand, successful bids should not have a financial incentive to exit their existing contract. Staff appreciates this change by PGE.

4). Transmission Acquisition Process

Briefly: PGE's Draft RFP included language aimed at ensuring long-term firm transmission. PGE's Draft RFP included a specific milestone[8] requirement as a 'threshold': only bids having reached this would be evaluated. Stakeholders were concerned that this was an overly high bar to reach given the timeline, while PGE argued that it was necessary to move quickly through the process to ensure a COD that qualified for the PTC.

[8] Phase four of the transmission study and expansion process (TSEP).

This issue was raised by all stakeholders (NIPCC, RNW, AWEC, CREA) and by the IE.

PGE's Response: In its Reply Comments, PGE modified the Final RFP to allow bidders to be earlier along in the transmission acquisition process[9].

Staff's Assessment: Staff appreciates this change. If acquiring long-term firm transmission is required in this RFP (an open question discussed above), this is a reasonable concession by PGE that balances bid reliability and accessibility.

5). PGE's Excess Transmission Rights

Briefly: BPA's BAA is constrained. If PGE is holding transmission rights in excess of its need, then requiring long-term firm transmission limits competition: independent bids have to compete for scare transmission rights, and its increased cost forces bids have to offer higher prices.

This issue was raised by all stakeholders (NIPCC, RNW, AWEC, CREA). The IE did not comment.

PGE's Response: In its Reply Comments, PGE clarified that it does not have excess transmission rights: its rights in excess of its average load are required to serve peak load, according to established 1-in-10 methodology.

Staff's Assessment: Staff has verified PGE's claim, and agrees that PGE is calculating peak demand according to the practice established in the previous several rate cases.[10] Staff notes that this could be an argument for accepting bids relying on less than long-term firm transmission, as PGE will likely attempt to sell this transmission in non-peak times.[11]

6). 15 vs 60 minute scheduling

Briefly: Renewables are intermittent, and scheduling its generation comes with some risk of under- or over-production. The longer the time period, the larger impact of missing delivery targets. Accordingly, PGE bears more balancing cost if the scheduling interval is shorter, and thus they argue for longer duration. PPAs prefer shorter duration, which limits their risk.[12]

[9] Any bid participating in the 2016 TSEP or that is in an individual study process.
[10] See PGE response to OPUC #144 from Docket No. UE 335.
[11] Though those attempts are of course not guaranteed.
[12] Allowing them to bid lower prices, increasing the likelihood of reaching the shortlist

NIPCC and RNW raised this issue, as did Staff in its Initial Comments. The IE suggested that PGE justify its position.

PGE's Response: In its Reply Comments, PGE reiterated its position that intra-hour scheduling shifts costs to ratepayers.

Staff's Assessment: The costs of balancing intra-hour generation are real, and will be paid by someone. PGE is right to highlight that intra-hour scheduling shifts those costs to the Company. That said, the Commission has already allowed the recovery of these costs. Indeed, this was the main justification for the building of the Port Westward 2 facility, a 220-megawatt natural gas-fired power plant. In their 2009 IRP, PGE stated:

> Our increasing level of intermittent energy resources necessitates that we maintain flexibility and load-following capability in our generation portfolio. As such, PGE is proposing a benchmark resource with a nominal generating capacity of up to 200 megawatts to potentially fill part of our future capacity needs.

The Commission has already allowed more than $320 million into the ratebase to build the Port Westward 2 facility specifically so that PGE is able to pay the costs associated with balancing intermittent resources. For this RFP, much of the costs of intra-hour scheduling have already been allocated to ratepayers, and thus they should not be incorporated into the cost of a PPA as well.

7). Specified Energy

Briefly: PGE sets the rules for PPAs missing 'Specified Energy' targets: PPA's over-producing are paid the Mid-C spot price, however, if the PPA under-produces, then the PPA must[13] pay compensation to PGE for the energy, transmission, and associated RECs that PGE otherwise would not have had to acquire.

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[14] to account for this risk, while the self-build option simply passes this increased cost (of under-production) onto ratepayers.[15]

NIPCC and RNW raised this issue, as did Staff in its Initial Comments.

---

[13] Under the proposed contract, which can be redlined as discussed below
[14] Lowering the probability they reach the shortlist.
[15] Put another way, self-build options pass greater risk onto ratepayers.

The IE differentiated between a PPA's failure to deliver energy and failure to meet availability (i.e. being available to harness the wind/sun, even if the wind doesn't blow/sun doesn't shine). The IE suggested that PGE's requiring compensation for energy delivery failure was too strict, and recommended that compensation payments only be required for failure to meet availability targets.

PGE's Response: In its Reply Comments, PGE stated that project owners should be responsible for variability and unpredictable generation.[16]

Staff's Assessment: Staff believes the issues raised by stakeholders and the IE are real, and present a competitive imbalance between PPA and self-build options. Staff supports the IE's recommendation that the only payments required should be from missing availability targets.

8). Redlines Diminish Score

Briefly: All the terms in the contract between PGE and a potential bid can be redlined, or changed, by the bidder. However, under the non-price scoring rubric, such modifications reduce the value of the non-price score. This raises the concern that these terms are practically unchangeable.

This issue was raised by Staff, NIPPC, and RNW.

PGE's Response: PGE did not mention this concern in its reply comments.

Staff's Assessment: PGE's approach is directly in conflict with Guideline #6 of Order No. 14-169, which states:

> The final draft submitted to the Commission must also include standard form contracts. However, the utility must allow bidders to negotiate mutually agreeable final contract terms that are different from ones in the standard form contracts.

It is true that PGE's reduction in non-price score is minimal (~10-20 points out of a possible 400), but that still does not excuse this deviation from the Guidelines. Any reduction for negotiating and then changing the terms of the contract should be removed.

9). Conditional Firm Bridge

---

[16] See section IV(a): Project Owners Should Be Responsible for the Costs of Intra-Year Variability and Unpredictable Generation: pg. 21.

Briefly: Draft RFP allowed a one-year bridge where PPAs could rely on conditional-firm transmission before acquiring long-term firm transmission. Stakeholders were concerned this was insufficient.

This issue was raised by NIPPC, RNW, and briefly by the IE.

PGE's Response: PGE increased the maximum time allowed for a bridge from one to two years.

Staff's Assessment: Staff appreciates this change, while maintaining the concerns about firm-transmission requirements discussed above.

10). Pseudo-Ties

Briefly: BPA and PGE have adjacent BAAs. A generation facility that wants to transmit electrons from BPA's BAA to PGE's BAA must pay both transmission and balancing costs.[17] However, a facility in BPA's BAA can be dynamically transferred to PGE's BAA using a pseudo-tie: all generation is immediately and automatically transmitted to PGE's BAA; BPA only charges the associated transmission costs, and PGE balances that resource as needed with their own generation mix. PGE recently established pseudo-ties for its Biglow Canyon and Tucannon River wind farms.

The concern is that if PGE can pseudo-tie any self-built resource, it can offer a lower price knowing those balancing costs will soon be replaced with lower balancing costs.[18] PGE has stated that PPAs cannot be pseudo-tied.

This issue was raised by NIPPC, CREA, and Staff. The IE did not comment.
PGE's Response: PGE clarified in its Reply Comments that for a variety of reasons, PPA's cannot be pseudo-tied.[19] They did not comment, however, on the competitive advantage a self-build option has.

Staff's Assessment: Staff believes PGE should provide assurance that all bids approach paying balancing costs the same, similar to the clarification under issue #1.

---

[17] BPA's rates available here:
https://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/FY18-19/BP-18%20Final%20Transmission%20Rate%20Schedules%20and%20GRSPs.pdf

[18] Given Port Westward 2 and participation in the EIM, it is reasonable to believe these balancing costs are lower. If they weren't, it wouldn't have made sense to dynamically transfer Biglow Canyon and Tucannon River.

[19] PGE Reply Comments, pg. 14.

11). Price vs. Non-Price Split (60/40)

Briefly: PGE evaluates bids based on its price and a variety of non-price factors, and the Company proposed in both its Draft and Final RFP that the split between these two be 60/40. Stakeholders are concerned about the non-price component is far less transparent, and should be minimized.[20]

For reference, Commission Order No. 91-1383 suggest that the price factor should receive between 50-70 percent of the consideration. PGE's past five RFPs had 60/40 splits. The recent PAC RFP had an 80/20 price/non-price split.

This issue was raised by NIPPC and Staff. The IE raised the concern as well.

PGE's Response: In both its responses to multiple IRs and in its Reply Comments, PGE merely reiterated why non-price scores are important, and that a 60/40 has been the norm. PGE did though modify its Final RFP to include a sensitivity which tests whether a different split would produce different results.

Staff's Assessment: This change is acceptable at this time, although Staff expects a stronger explanation of why the specific split chosen is appropriate in future RFPs.

12). Escalation Rate

Briefly: Given its congestion, it is very reasonable to assume BPA's transmission and balancing costs will increase in the future. How fast these costs increase, or the escalation rate, is a significant risk for any PPA. As PGE can pass these costs onto ratepayers, the cost of the benchmark bid carries more risk to ratepayers. To alleviate this concern, NIPPC suggested publishing the escalation rate used by the benchmark bid.

This issue was raised by NIPPC and Staff. The IE did not comment.

PGE's Response: PGE stated that bidders could submit[21] both variable and fixed costs; by including balancing costs in their variable costs, bidders can pass some of that risk through to PGE.

Staff's Assessment: It is not clear based on PGE's explanation what harm would be caused by publishing the escalation costs assumed by the benchmark bid. As this

[20] NIPPC provides a lengthy appendix critiquing many aspects of the non-price score.
[21] At some redlining cost, mentioned above.

presents a far simpler solution to this real problem, Staff believes PGE should modify its Final Draft RFP to include these assumed escalation costs.

13). Interconnection Study Agreements

Briefly: A necessary component of transmission is the interconnection to high-voltage lines, which take time and effort. In its Draft RFP, PGE required bids to have completed this process[22] to reach the Shortlist.

This issue was raised by NIPPC and RNW. The IE highlighted the issue as well.

PGE's Response: PGE modified the RFP to change the threshold to an earlier interconnection step[23].

Staff's Assessment: Staff appreciates this change.

14). South of Allston Constraint

Briefly: BPA's transmission is notably constrained at the South of Allston (SOA) flowgate. Stakeholders cite this constraint as a reason why requiring long-term firm transmission for PPAs as onerous.

This issue was raised by NIPPC and RNW. The IE did not comment.

PGE's Response: PGE did not comment.
Staff's Assessment: Staff has concerns discussed above regarding long-term firm transmission requirements. However given BPA's decision to not upgrade their network, Staff believes this to be realistic constraint on the system going forward.

15). NPVRR Duration / Generic Fill

Briefly: Wind farms are estimated to last 30 years, but PPAs are generally for shorter time periods. To compare the cost of the different options, the costs associated with 'generic fill' is added to as many of the years after PPA to display two options with similar resources. What is considered 'generic fill' might be tangibly different than the costs of the PPA. Further, by changing the duration of economic analysis (today's value of the overall revenue requirement, or NPVRR), the PPA (and additional generic fill) will look better or worse.

---

[22] Possessing a System Impact Study Agreement.
[23] Having completed a Facilities Study Agreement.

This issue was raised by both NIPPC and RNW. The IE did not comment.

PGE's Response: PGE stated in its Reply Comments that it would perform a planning horizon sensitivity analysis to determine whether a different present-value duration would change the Shortlist order.

Staff's Assessment: Staff appreciates the agreement to perform a sensitivity analyses, which is sufficient for this RFP to determine the relative impact this has on PPA. However, Staff is very concerned with the practice of generic fill, and believes at a minimum it should be much more transparently explained in the future.

16). Montana Wind

Briefly: Montana has a significant amount of wind resources, which are particularly attractive to residents in the Pacific Northwest as it blows at different times from Columbia Gorge wind. The Commission specifically ordered that in the RFP process PGE "discuss aspects of RFP design and scoring that impact the treatment of Montana wind resources."[24] RNW has used Montana as an example of how the requirement of long-term firm transmission limits the development of Montana's resources.

This issue was also raised by Staff. The IE did not comment.

PGE's Response: PGE did not specifically address Montana's development (but did in Staff's opinion follow the order cited above).

Staff's Assessment: No specific changes are suggested from this issue, but it does highlight a real impact of PGE's reliability-rigidity, and reinforces concerns raised above regarding long-term firm transmission.

17). Permitting as Threshold Obligation

Briefly: The IE was concerned that permitting should not be a threshold obligation, but rather part of the non-price score. No stakeholders stated this concern.

PGE's Response: PGE in its Reply Comments said it will change the permit requirement to a non-price factor.

Staff's Assessment: Staff appreciates the change.

18). PPA PTC

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

Briefly: PGE requires some assurance that bidders are able to obtain the PTC. NIPPC questioned whether this is necessary if the PTC is already reflected in the price. No other stakeholders raised this concern.

PGE's Response: PGE did not comment.

Staff's Assessment: Staff feels this to be a part of a broader question surrounding PURPA. In this RFP, it does present a trade-off between reliability and cost, however, Staff believes the stakes are low either way.

19). COD Extension

Briefly: AWEC raised the possibility that generators could still qualify for the PTC even if their COD is after 2020 by using a safe-harbor provision. No other stakeholders raised this concern.

PGE's Response: PGE did not comment.

Staff's Assessment: Similar to #17, PGE would likely cite reliability concerns to justify their aversion to this change. However, an extension of this deadline to the last possible COD could enable a winning bid from a 2018 RFP with a COD of 2022, the benefits of which don't appear to Staff to justify the costs. Accordingly, Staff does not believe any change in the COD is necessary.

20). Prohibiting Capital Additions

Briefly: NIPPC raised the issue that the PPA form as proposed prohibits capital additions to any winning bids, which they claim unnecessarily limits beneficial improvements and expansion that generators would otherwise be willing to finance. No other stakeholders raised this concern.

PGE's Response: PGE did not comment.

Staff's Assessment: Similar to #17, Staff believes this is part of a larger PURPA discussion. For this RFP, however, PGE at a minimum should justify the need for this provision: where has this been a problem before?

21). Damage Cap

Briefly: NIPPC also raised the issue that the PPA form as proposed limits the damages caused by PGE to only $100,000. NIPPC also provided an example where PacifiCorp was forced to pay significantly more than this cap to a developer. No other stakeholders raised this concern.

PGE's Response: PGE did not comment.

Staff's Assessment: Staff agrees with NIPPC: this proposed cap is too low, and bids should not face point reductions for modifying/redlining the PPA form.

Conclusion

Staff again appreciates PGE's efforts to inform both Staff and stakeholders, as well as make significant changes from its Draft RFP to the Final RFP. Many of these changes alleviated real concerns from Staff, stakeholders, and the IE, and improve the fairness of the RFP. However, there is still room for necessary improvement. Staff recommends the Commission approve PGE's 2018 RFP only with the conditions and modifications described on page 4 of this Staff Report. Some of those modifications merely require PGE to justify its position on a particular issue, but others are much more substantive. With these modifications, however, Staff recommends approval of the 2018 RFP.

PROPOSED COMMISSION MOTION:

Approve PGE's Final Draft 2018 RFP for Renewable Resources subject to the conditions described on page 4 of this Staff Report.