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October 26, 2018

Via E-filing

Mr. Mark Johnson
Executive Director
Washington Utilities & Transportation Commission
1300 S. Evergreen Pk. Dr. S.W.
P. O. Box 47250
Olympia, WA 98504-7250

Attn: Filing Center

RE: In the Matter of Public Utilities Regulatory Policies Act, Obligations of the Utility to Qualifying Facilities, WAC 480-107-105
Docket No. U-161024

Dear Mr. Johnson:

Please find the Reply Comments Regarding Proposed RFP Rules of the Northwest and Intermountain Power Producers Coalition in the above-referenced docket.

Thank you for your assistance. Please do not hesitate to contact me with any questions.

Sincerely,

Irion A. Sanger

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

U-161024

In the Matter of Rulemaking for Integrated Resource Planning, WAC 480-100-238, WAC 480-90-238, and WAC 480-107	)))))))	NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION REPLY COMMENTS REGARDING PROPOSED RFP RULES

I. INTRODUCTION

1. In accordance with the Washington Utilities and Transportation Commission's (the "Commission" or "WUTC"), October 11, 2018 Notice in this docket, Northwest and Intermountain Power Producers Coalition ("NIPPC") submits these Reply Comments regarding the Commission's draft rules related to competitive procurement for electric utilities (WAC 480-107).

2. In these comments NIPPC provides: 1) responses to the new questions posed by the WUTC in its October 11, 2018 Notice of Opportunity to File Written Reply Comments; and 2) responses to comments from certain other parties in this proceeding.

II. COMMENTS ON UTC's SPECIFIC QUESTIONS

1) Independent Evaluator Requirement.

3. The Commission requested feedback on a new proposal, designed to encourage the use of an Independent Evaluator ("IE"). Under this proposal, the Commission would allow a utility to shorten the ninety-day process between when a utility files a proposed RFP with the Commission and when the Commission approves the RFP, to a process where there is a thirty-day comment

period, and the Commission would approve the RFP at its next regularly scheduled open meeting following the comment period. This process would occur so long as the utility has obtained the services of an IE for the RFP, and its retention of the IE was early enough to allow the IE to participate in the formulation of the RFP. The Commission asked specific questions about this proposal, which NIPPC addresses below.

a. Does the incentive of a shortened regulatory approval process for the RFP encourage the use of an IE?

4. NIPPC does not support using a shortened period of review as an "incentive" to encourage a utility to use the services of an IE. The purpose of retaining an IE should be to help ensure that an RFP process is fair, well-analyzed, and that it is designed to ensure the best resource options for meeting customers' needs. In NIPPC's view, these reasons justify *requiring* electric utilities to use the services of an IE under the circumstances where the thresholds in the rules are met, and there is no need to encourage the utilities to do what the rules should require.

5. The final rules should ensure that the IE is used as an important to tool to design fair and beneficial RFPs, and that stakeholders have an opportunity to review and comment on any draft RFPs. NIPPC values this opportunity for review, and it is a necessary and appropriate part of the Commission's implementation of its duties to protect customers. It would be counter-productive to determine that if a utility uses one tool for the protection of customers (an IE), that the other tool (review of the RFP) should be diminished in a material way. NIPPC believes that a thirty-day comment period is too short to ensure that parties have a chance to conduct meaningful review, discuss with their findings with their principals or members, conduct any necessary research or investigation, and develop effective and clear comments for the Commission's review.

b. Does the use of an IE adequately assure sufficient review of the RFP considering the tradeoff in the length of the stakeholder comment period?

6. Although the use of an IE helps assure a fair and effective RFP, it is not a given that it will always do so. The Commission should not see the IE as the "be all and end all" solution to designing a fair and transparent RFP. Even with the best and most professional IE, it is vital that the Commission's review process allow interested stakeholders an opportunity to review and provide comments to the Commission. It will serve no one's interests to have a rule that truncates review of the RFP due simply to the fact that an IE was utilized. As described above, the Commission should take reasonable steps to ensuring fair and efficient RFP processes in its rules, and this should include a requirement to utilize an IE *and* an adequate review and comment period by interested stakeholders and Commission Staff.

7. If the Commission is inclined to shorten the ninety-day review period, NIPPC recommends that the Commission take the approach recently adopted by the Public Utility Commission of Oregon in its competitive bidding rules. Those rules allow for an eighty-day review period, and allow a party to request to extend the period for an additional thirty days upon a showing of good cause.[1]

2) Role of the Independent Evaluator.

8. The Commission states in its Notice that the rule requirements regarding use of an IE will be the minimum requirements a utility must meet, and that a utility may contract for more in-depth involvement by an IE at its discretion. In light of this, the Commission asks what parties

[1] OAR 860-089-0250(6).

envision is the proper role of an IE under the rules. The Commission asks parties to consider the following questions, which are each followed by NIPPC's response.

a. How deeply should the IE be involved in the development of the RFP? Should an IE independently score all bids, a sampling of bids, or only bids resulting in utility ownership?

9. NIPPC first points out that it does not believe it is practical to expect a utility to treat the rules regarding the use of IEs as only a minimum, and then voluntarily go above and beyond the requirements in expanding an IE's role beyond what is required. To the contrary, the Commission should bear in mind that the purpose of an IE is to assist in overseeing the utility's actions, and provide a second opinion as to the utility's analysis and conclusions. Likely in all cases, the Commission should expect that the level of involvement demanded by the rules will be the level of involvement that an IE will have.

10. NIPPC does not see any valid reason why the IE should not be given an expansive role in the development of the RFP. A qualified IE has the expertise to develop and manage an entire RFP process, and this process would be superior to having a utility run the process in terms of providing protection to customers, and ensuring a truly even field for independent power producers that want to compete for the opportunity to provide low-cost, low-risk resources to customers.

11. The IE should certainly do more than independently score only a sampling of bids. In other Commission processes, sampling is generally used where there is so much data that a review of all data is not practical. NIPPC does not anticipate that this would be the case when it comes to RFP responses. And, a sample would mean that one or more projects would go unreviewed by an IE, meaning that these projects would be measured against projects that likely were subject to a very different level of scrutiny, and may have a much more robust record of

their associated review. This would seem to introduce the potential for unfairness into the RFP process by potentially resulting in "apples to oranges" comparisons between certain bids.

12. If a utility project has bid into an RFP, then the IE should independently score that bid. And, because other projects will be competing against that bid, they too should be evaluated by the IE to ensure that the IE can directly compare those projects with the one(s) bid by the utility.

b. How should the IE be involved in communication between the utility and bidders?

13. The communications between the utility and bidders are of major importance within an RFP process. After all, it is these communications where a utility seeks additional information, provides responses to questions a bidder may have, and potentially starts to judge a project. Because all of these factors ultimately conclude with a utility's assessment of an individual bid, the IE should be heavily involved in these communications. To the extent that these communications are done by email, it is easy enough to copy the IE on all communications. And, where such communications are by phone, or through in-person meetings, it is also easy to include an IE either in person or by phone. These safeguards help ensure the fairness and integrity of an RFP process, and the Commission should require them.

c. Should there be a requirement that the IE document and file all communications with the Commission?

14. The IE should be allowed, as described above, to participate in and monitor all communications between the utility and the bidders. Such communications should be knowable by parties to the case, and therefore appropriate and reasonable documentation of such communications, such as notes, summaries, etc., should be subject to production.

d. In situations where there is a direct conflict between the IE and the utility should additional process be proscribed?

15. The purpose of the IE is to help ensure a fair and effective RFP process. In the event that there is a direct conflict between the IE and the utility, this would indeed be cause for concern, or at least further investigation. In such cases, NIPPC believes there would be good cause to ensure that sufficient review and discovery could occur. NIPPC recommends that parties be allowed to request up to thirty additional days for review during the course of RFP proceedings, for good cause shown. A direct conflict between the IE and the utility should be sufficient cause, if the dispute is material and relevant to an important issue in the process.

3) Conservation RFP.

16. NIPPC does not have comments regarding this question.

4) Market Purchases Resource Adequacy Exemption.

17. On the topic of resource adequacy, and the rules' proposed reliance on the Northwest Power and Conservation Council's resource adequacy assessment, the Commission notes that during the workshop, stakeholders suggested adding additional language. This additional language would limit the degree of reliance on the market a utility may have in order to qualify for the automatic exemption provided in the rules. The Commission asks:

> **a. If this idea were to be incorporated into rule, what level of reliance on the market would be reasonable?**
>
> **b. Should the degree of reliance be tied to a separate metric? If so, what metric should be used?**
>
> **c. Should an RFP be required for firm resources whenever there is significant market risk?**
>
> **d. This section also uses the undefined term "short-term market purchases." Please provide comments on the following proposed definition: "Purchases of energy or capacity on the spot or forward market contracted for a term less than four years."**

18. NIPPC recommends that the rules should not overly proscribe or limit the amount of reliance upon the market that is reasonable. Generally, Pacific Northwest markets are robust, and they may become significantly more so as regional transmission markets develop. However, NIPPC supports an RFP for firm resources when there is a significant market risk. Finally, NIPPC does not believe the rules need to include a definition for short-term market purchases because that term can change over time. If the Commission intends to include a definition in the rules, then the proposed definition is currently reasonable ("Purchases of energy or capacity on the spot or forward market contracted for a term less than four years.").

5) RFP Transparency.

19. In its Notice, the Commission cites comments that Public Counsel provided, which would modify the rules to regarding transparency in the RFP's evaluation rubric. Staff added one additional edit, such that the rules would read: "The RFP must include a sample evaluation rubric that either quantifies the weight each criterion will be given during the project ranking procedure or provides a detailed explanation of the aspects of each criterion specifically identified that would result in the bid receiving higher priority." Regarding this suggestion, the Commission asks:

> **a. Is this language sufficient to elicit the transparency stakeholder's desire in an RFP? Is this language reasonably flexible?**
>
> **b. Will this requirement result in the utility being tied to and limited to criterion established prior to review of the bids that does not fit or account for the complexity of the evaluation of actual bids?**
>
> **c. Should instead the utility be required to establish contemporaneous documentation of its criterion prior to receipt of bids and provide its contemporaneous reasoning for any changes to its criterion?**

20. NIPPC generally supports the proposal regarding scoring criteria by Public Counsel, as modified by Commission Staff. As noted in earlier comments, NIPPC believes the Commission would be well-justified to apply an even more prescriptive set of criteria to limit the use of subjective scoring criteria that can undermine the process. Specifically, NIPPC continues to believe that the Commission would be justified in barring the use of non-price scoring criteria unless the utility can demonstrate those criteria cannot be converted to minimum bidder criteria in the RFP, as the Oregon Public Utility Commission recently did in its RFP rulemaking.[2] However, NIPPC nevertheless supports the Public Counsel proposal as modified by Staff given the apparent consensus around this definition.

21. As NIPPC's prior comments have explained, transparency of the scoring process and scoring criteria is a fundamental element to any fair bidding process.[3] The problem is most significant in the case of so-called "non-price" scoring criteria, such as the quality of the development team, permitting status, credit evaluation, status of interconnection and transmission. Unlike a price per unit of energy or capacity delivered, scoring criteria for these non-price elements of a bid can be inherently subjective. Yet it is common for a utility to allocate 20 to 40 percent of the bids' individual scores to these non-price attributes. Providing transparency as to the scoring criteria would assure the bidders that all bids will be evaluated according to the same metric, as opposed to some ad hoc, subjective analysis by the utility's evaluation team. It will also limit the ability of the utility to arbitrarily boost the score of its preferred utility-ownership bid. Further, transparency early in the process will allow interested

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2 See NIPPC's Comments at 19-21 (Sept. 21, 2018) (citing Re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources, OPUC Docket No. AR 600, Order No. 18-324 at 12-13 (Aug. 30, 2018) (adopting OAR 860-089-0400).

3 See Id.

stakeholders to comment upon and possibly achieve a change to the utility's initially proposed scoring weights where a change in the utility's proposed weights is justified.

22. The Public Counsel's proposal, as modified by Staff, will provide added transparency to Washington RFPs. NIPPC understands the proposal to require that the RFP include a detailed description of the score card that will be used to evaluate the bids received in the RFP, including a detailed description of the characteristics that will result in a high score. Assuming that is the case, NIPPC supports the proposal. An example of this type of score card information is attached, as Attachment A, to these comments for reference, from the recent Portland General Electric Company's ("PGE") 2018 Renewable RFP.[4] The PGE 2018 Renewable RFP was not subjected to the full requirements of the recently adopted Oregon administrative rules referenced above, but it provides a good example of an adequately transparent scoring explanation in the case where the utility is allowed to heavily weight the non-price criteria.

23. As can be seen in the PGE RFP document, the scoring criteria are transparently presented in a table that sets forth the relative weight of each price and non-price characteristic.[5] In this case, the price score was worth 600 total points and the various non-price categories were worth a total of 400 points, which consisted of the following subcategories: 100 points allocated to Project Development criteria, 130 points allocated to Project Physical Characteristics, 120 points allocated to Project Performance Certainty, and 50 points allocated to Credit Evaluation. The PGE RFP document also contains a detailed explanation of the specific characteristics that will result in a full allocation of the available points for specific non-price sub-categories.[6] This type

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4 Also available online at: https://www.portlandgeneralrfp2018.com/documents/ (last accessed Oct. 24, 2018).

5 Attachment A, PGE's 2018 Renewable RFP, Appendix H at 8.

6 Id. at 11-17.

of transparency is essential to provide bidders the assurance that the evaluation is being conducted objectively and equally across all bids. There is no valid reason for a utility to fail to use the same score card for each bid or to withhold this type of information from the bidders and stakeholders.

24. The specific information relevant to each RFP will likely change from one RFP to the next. Therefore, NIPPC does not propose use of a uniform score card that might apply to all solicitations. Instead, the utility's proposed score card and explanations should be made available for public comment and revisions by the Commission before the individual RFP is released for bidding.

25. NIPPC opposes any changes to the scoring criteria once the RFP is released to bidders. The question here suggests that the scoring criteria established prior to review of the bids may not account for the complexity of the evaluation of actual bids, and thus may need to be changed during the bidding process. However, it is hard to understand how the criteria relevant to the bids could be unknown at the time of the solicitation. On the other hand, any change to the scoring criteria after receipt of bids would severely undermine the integrity of the process for the reasons discussed above. If the utility can modify the scoring criteria during the process, the RFP becomes a moving target for the bidders, who will be left to assume that the utility will change the criteria to ensure the utility-owned bids will score higher and win the solicitation.

26. In sum, NIPPC recommends using the language proposed by Public Counsel as modified by Staff for purposes of developing a rule related to the scoring criteria.

III. COMMENTS ON OTHER PARTIES' COMMENTS

1) NIPPC's Two-Stage Bidding Process Is Superior to PacifiCorp's Proposal

27. In NIPPC's prior comments, we demonstrated that a two-stage bidding process is standard practice in bidding procedures across different industries where one bidder is an interested party with decision-making authority in the process.[7] PacifiCorp has made a proposal that is not a two-stage process and would provide none of the benefits of the NIPPC proposal.

28. NIPPC's proposal is simple: first the utility determines the best utility-owned bids; second, the utility makes the details regarding the winning utility-owned bid known as the price-to-beat by the independent power producer bids. NIPPC provided examples of bankruptcy and corporate acquisitions and mergers where an interested party that is also a decision-maker in the process must conduct a two-stage process to ensure that it does not engage in preferential evaluation of its own bid. In those cases, the two-stage process is intended to protect the interest of third parties who will be affected by the transaction – in the case of corporate law, the two-stage process for management's acquisition of the corporation protects shareholders; in bankruptcy, the stalking horse bid protects the creditors of the bankrupt company. Similarly, here, the utility's ratepayers are protected by the proposed requirement to evaluate utility ownership options first and allow independent power producers to bid against the best utility-ownership offer. Given that a two-stage process is used in other commercial contexts to protect against self-dealing, the Commission should also use such a process to protect against utility self-dealing.

29. In written comments and at the workshop on November 2, 2018, PacifiCorp stated that it proposed an alternative form of a two-stage bidding process. However, PacifiCorp only

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[7] See NIPPC's Comments at 21-23 (Sept. 21, 2018).

proposes that the utility-owned bids be received first, not that the winning utility-owned bid be made known to the independent bidders to provide the price-to-beat for those bids for an independent-ownership structure.[8] Under PacifiCorp's proposal, the utility bids are sealed until after receiving the independent-ownership bids, but the process does not include any type of stalking horse offer or utility "price-to-beat" phase as NIPPC proposed. PacifiCorp's proposed restriction (sealing the utility-owned bids) would certainly be necessary to prevent the utility from potentially altering bids in the case where all the bids were evaluated in a single phase. But PacifiCorp's proposed single-phase restriction is not equivalent to the processes used in other contexts to prevent a self-interested party from influencing the solicitation to its advantage. The two-stage bidding process provides the type of transparency and protections that have been required in other commercial contexts where a self-interested party is involved in the evaluation of the transaction. It is not at all clear why the investor-owned utility industry is any different.

30. PacifiCorp argued at the workshop that NIPPC's proposal will encourage independent-ownership bids that are not commercially viable – colorfully suggesting the winning bid will be submitted by "three guys in an Avis." However, this perceived problem is unfounded because the RFP will contain other restrictions that would prevent commercially unviable bids from prevailing. The RFP would typically contain certain minimum bidding qualifications, and the resulting power purchase agreement would contain significant creditworthiness guarantees or security requirements to support damages for non-performance. Thus, while PacifiCorp's concern about "three guys in an Avis" was amusing, the other requirements of the RFP would prevent three guys in an Avis from prevailing in any PacifiCorp RFP unless they possessed requisite financial backing, development expertise, and a viable plan to perform on the bid.

[8] PacifiCorp's Comments at 11 (Sept. 21, 2018).

31. NIPPC notes that while bidding criteria are appropriate for the above-described reasons, it is important to ensure that they are flexible enough to allow creative competitive options to succeed in the RFP process. Experienced development teams, though sometimes small, have brought multiple gigawatts of power generation capacity successfully online in the Western Interconnection in recent decades, including gas, hydro, wind, and solar, some of which was a result of winning utility RFPs and for single multi-hundred MW projects. The ability of these developers to participate in RFP processes should be encouraged, as it ensures that a full array of competitive options are made available to benefit ratepayers.

32. The utilities have also complained that the two-stage bidding proposal will unfairly disadvantage utility-ownership bids. That complaint incorrectly assumes that the Commission's objective is to ensure the utility's shareholders are entitled to own and profit from generation assets. Despite the lack of such a right, investor-owned utilities in the Northwest have historically enjoyed substantial advantage in the generation market for decades. Instead of perpetuating the utilities' generation monopoly, the Commission is instead responsible for ensuring the that the bidding process results in the least-cost, least-risk resource for the utility's captive ratepayers. The utility has an obvious and inherent incentive to engage in self-dealing to ensure that any RFP for a generation resource results in the new resource being placed in the utility's rate base where it can provide long-term profits to the utility's shareholders. That incentive is little different from the incentives that two-staged processes were developed to prevent in other contexts, such as bankruptcy and corporate law. If the utility-owned bids are the lowest cost bids, then the utility and the ratepayers will still end up with the same result under the two-stage process. However, the two-stage process gives the ratepayers the opportunity to

possibly obtain a lower cost resource by subjecting the self-interested utility-ownership bid to the market to see if any qualified bidder can beat the price with a commercially viable offer.

33. In sum, while PacifiCorp's proposal to seal utility-owned bids would be necessary in an RFP with single-phase evaluation of all bids, NIPPC maintains that the Commission should adopt the two-stage process to protect against utility self-dealing and provide the lowest cost resource to ratepayers.

2) Discussion Regarding IE Costs

34. There was discussion at the Commission workshop regarding the costs of IE participation in RFPs. In Oregon's recently concluded competitive bidding rulemaking, the Oregon Public Utility Commission Staff provided an analysis of the IE costs. Staff's comments are attached to this document, for the Commission's reference, as Attachment B.[9]

[9] Also available at https://edocs.puc.state.or.us/efdocs/HAC/ar600hac11732.pdf (last accessed Oct. 24, 2018).

Dated this 26th day of October 2018.

Respectfully submitted,

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Of Attorneys for the Northwest and Intermountain
Power Producers Coalition

Attachment A

PGE's 2018 RENEWABLE RFP-APPENDIX H

SCORING PROCEDURES

APPENDIX H

SCORING PROCEDURES

Overview

Appendix H details the RFP's Price and Non-Price Scoring components, which all bids will be subject to. The maximum possible price score will be 600 points, and the maximum possible non-price score will be 400 points. The maximum overall offer score a bid may receive is 1,000 total points. This 60/40 weighting of the price and non-price scores provides a balance between cost and risk, similar to that in the 2016 IRP, and consistent with past Commission-approved RFP processes. Appendix H also provides additional description on PGE's portfolio analysis methodology.

Price Scoring

Price accounts for 60% of the maximum overall offer score, or a maximum of 600 points out of 1,000 total. The price score will be determined by the ratio of the offer's projected total cost to its total benefits using real-levelized, or annuity methods, per Guideline 9a of Order No. 14-149 (Oregon Competitive Bidding Guidelines). The price scoring will incorporate benefits of expected energy value, capacity value, and flexibility value associated with each offer.

Price Scoring Ratio

Following the quantification of offer costs and benefits, including any necessary offer price adjustments (as outlined in the RFP main document section 8.5), each offer's component cost and benefits will be converted to a cost-to-benefit price score ratio. Real-levelized offer costs, divided by the equivalent real-levelized benefits value (incorporating energy, capacity, and flexibility benefits) will be the basis for the offer's price ratio.

Score Allocation

Once price ratios have been calculated for all offers, PGE will allocate price scoring points on a scaled basis, with 600 points allocated to the offer with the lowest (best) price ratio. The point allocation system is illustrated in the tables below, which are populated with fictitious cost-to-benefit and price scores for the sole purpose of illustrating the score allocation method.

Table 1. - Illustrative Scoring Example - Cost-to-Benefit Score

Cost-to-Benefit Ratio (%)	Price Score
75%	378
50%	528
80%	348
91%	282
60%	468
38%	600
88%	300
42%	576
101%	222

Table 2 - Illustrative Scoring Example - Price Ratio to Price Score

	Price Ratio	Price Score
Lowest (Best)	38 %	600
Highest	101%	222
Average	69.4%	411
Ratio Highest/Lowest	2.66	2.70

The lowest price ratio offer will receive the highest amount of points possible. All other offers will receive a scaled score, out of the 600 possible points, depending on their relative scores compared to the best score:

The lowest offer with a 38% price ratio will receive 600 points;

Any offer at or above a 138% price ratio will receive 0 points; and

An offer with a 75.0% price ratio will receive:

600-[600*(75%-38%)]

= 600-(600*37%)

= 600-222

= 378

Determination of the Energy Value

An offer's energy value reflects the value of energy generated throughout the offer's economic life or term. Energy value for the duration of the offer's term is expressed on a present-value basis and included in the denominator of an offer's cost to benefit price score ratio. The energy value will be based on the offer's simulated dispatch and the projected revenue associated with PGE's hourly market price forecast. The methodology used to create the hourly market price forecast is further described in Exhibit C, the 2016 IRP and the 2016 IRP Update.

Determination of Capacity Benefits

An offer's capacity benefit reflects PGE's need to acquire new, physical capacity resources due to the offer's estimated system capacity value. PGE is facing a capacity deficit, and requires capacity products, to otherwise displace the need to contract with or construct new peaking generating facilities. The capacity benefit will be included in the denominator of the offers cost to benefit price score ratio.

An offer's capacity benefit will be calculated as the product of the offer's capacity value and the avoided capacity cost. The product's capacity value will be calculated annually using the Renewable Energy Capacity Planning (RECAP) model. RECAP is described in Chapter 5 of the 2016 IRP. The model has been updated to accurately reflect the assumptions included in PGE's 2016 IRP Update filed in March 2018. The offer's capacity value will be expressed as the quantity of avoided simple-cycle combustion turbine (SCCT) needed to meet PGE's long-term capacity targets. The avoided capacity cost will be based on a per kilowatt, real-levelized cost (net of wholesale revenues) of a simple-cycle combustion turbine (SCCT). The assumed costs and performance of the SCCT are consistent with 2016 IRP capital costs and performance metrics (described in Chapter 7) operated under the updated reference case gas and wholesale power prices. The product of the offer's annual capacity value and levelized avoided capacity cost constitute the offers annual capacity benefit. Capacity benefit for the duration of the offer's term is expressed on a present value basis and included in the denominator of the price score ratio.

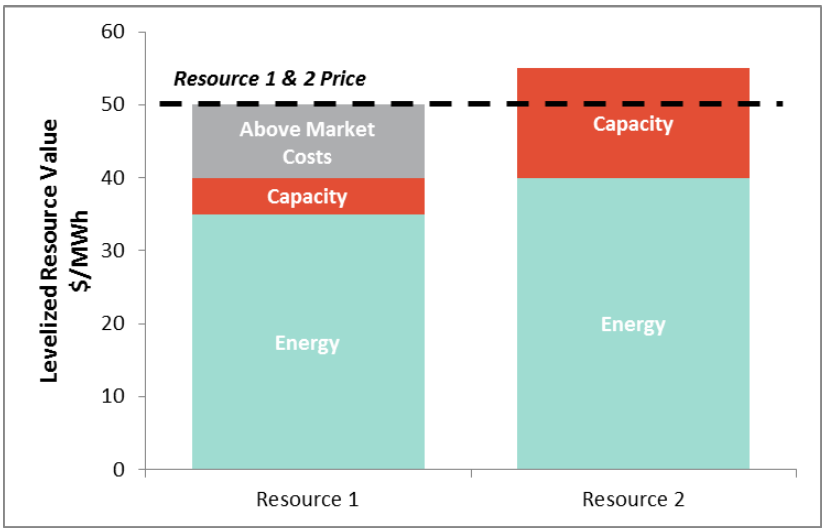
Determination of Flexibility Benefits

The flexibility value associated with an offer reflects any additional value that the offer may bring to PGE's generation portfolio due to its ability to ramp, respond to forecast errors, and/or provide ancillary services that is not captured by its energy value. PGE approximates flexibility benefits using the Resource Optimization Model (ROM), which the Company relied on in the 2016 IRP to quantify flexibility value associated with energy storage systems and the costs due to flexibility challenges (i.e., integration costs) associated with variable renewable resources. An offer's flexibility benefit is calculated using a methodology further explained in Example B. The flexibility benefit for the duration of the offer's term is expressed on a present value basis and is included in the denominator of the offer's cost-to-benefit price score ratio.

Price Screen

The cost-containment screen will be unique for each resource evaluated by PGE. The screen will be elevated for resources that provide more value to PGE customers due to the resource's geographic diversity. For this reason it is possible that a lower priced resource does not pass the economic screen, while a higher priced resource passes the economic screen due to increased resource value (e.g., higher capacity contribution, more valuable energy production profile or higher flexibility value). For example, Figure 1 illustrates a possible application of the proposed cost-containment screen. Resource **1** and Resource 2 have the same resource pricing. However, Resource 1's levelized cost exceeds the resource's energy, capacity and flexibility value. The resource is found to have above-market costs on a real-levelized forecasted basis and does not pass the economic screen. Resource 2 passes the economic screen as its resource value exceeds the resource cost.

Figure 1: Example of cost containment screen



It is PGE's expectation that the most economically competitive resources are capable of passing the proposed cost-containment screen. Table 3 provides an example of the applicable economic screen for generic 100 MW renewable resources.

Table 3: Example energy and capacity values for generic 100 MW resources*

	Gorge Wind ($/MWh)	Solar ($/MWh)	MT Wind ($/MWh)
Energy Value	$ 44.47	$ 38.70	$ 44.05
Capacity Value	$ 6.73	$ 8.15	$ 12.72
Total	**$ 51.20**	**$ 46.85**	**$ 56.78**

*Generic wind and solar resources are not considered dispatchable and therefore do not include flexible value.

Were these generic IRP resources to be evaluated within the RFP, the resources would only pass the cost-containment screen if priced below the total resource value. Importantly, each actual resource offered into the RFP will be screened against its unique resource value (not a generic threshold).

Non-Price Scoring

Non-Price accounts for 40% of the maximum overall offer score, or a maximum of 400 points out of 1,000 total. The non-price scoring will capture elements of the offers that are not easily captured in the price scoring. This is consistent with the RFP Guidelines, specifically 9a. The four main areas of focus are Development Criteria, Physical Characteristics, Performance Certainty, and Credit. See attached Exhibit A for the detailed Non-Price Scoring Rubric.

Portfolio Analysis

Portfolio modeling will provide PGE with additional information regarding the cost and risk profile of all offers considered. Portfolio analysis methods, consistent with the 2016 IRP, will demonstrate how resources perform together, on a cost and risk basis, due to their specific size, term, portfolio capacity value, and portfolio flexibility value.

Portfolio Construction

Portfolio analysis begins with the assembly of portfolios evaluating many different unique combinations of resources. The candidate portfolios will be developed through multiple techniques including 1) portfolio size optimization, 2) portfolio net-cost optimization, 3) cost-screened permutations, and 4) additional analyst selected portfolios (if necessary). The specific methodologies used to construct portfolios are described in further detail in Exhibit D.

Each portfolio will include sufficient resources to meet the RFP targeted capacity need in each year. The unique portfolio capacity value for each portfolio will be calculated using the IRP's RECAP methodology. The portfolio capacity calculation will recognize the resources' capacity diversity included in each portfolio. The RECAP model is described in Chapter 5 of the 2016 IRP. Any portfolio whose capacity contribution does not meet the RFP capacity target will also include a specified fill resource ('fill'). Including a fill resource ensures the portfolio incorporates the total cost necessary to meet the RFP capacity target in each year of the analysis. The specified fill resource will be sized to fulfill the resource target in each year of the analysis.

The specified fill resource will have cost and performance characteristics comparable to the average cost and performance of new resources of like product type offered into the RFP.

Portfolio Analysis

Portfolio analysis will test combinations of resources across multiple futures. The futures will evaluate portfolio exposure to multiple scenarios of gas prices, carbon costs, and hydro conditions. The futures are discussed in Exhibit C. For each portfolio, the relevant resources' variable costs and energy benefits will be calculated recognizing AURORA results under 27 economic and hydro futures. The variable net income for each resource will be reported annually for all futures. The AURORA dispatch simulation is described in Exhibit C.

A unique portfolio flexibility value will be calculated using the portfolio flexibility tool. The portfolio flexibility calculation will recognize the flexibility diversity included in each portfolio. The portfolio flexibility calculation is further detailed in Exhibit B.

For each portfolio, the portfolio flexibility value and the relevant resources' net incomes will be subtracted from the relevant resources' fixed costs to calculate the portfolio's total net cost for each future.

For each portfolio, the total present value net cost for years 2019 through 2050 under each future will be calculated to estimate the cost impact of the additions on the PGE system. This expected cost impact will be measured as the total portfolio net present value of revenue requirement (NPVRR) under reference case conditions. Portfolio risk will be evaluated using the standard deviation of future results. Portfolios will be ranked according to a blended cost and risk metric based 50% on reference case expected cost and 50% based upon the standard deviation of portfolio costs. In addition, portfolio risk will be characterized using additional IRP risk metrics including severity, variability, and durability as described in the 2016 IRP Chapter 11.

Portfolio results will be stress tested under multiple resource targets and qualifying facility planning scenarios. Specifically, PGE will test a 2018 through 2040 planning horizon sensitivity in addition to a 2018 through 2050 base planning horizon.

Portfolio analysis performance will be based on the inclusion of specific offers across multiple top-performing portfolios. Those resources that appear most frequently in top-performing portfolios are those that best reduce cost and economic risks. However, non-price factors are not evaluated or considered in portfolio analysis.

Exhibit A – Scoring Criteria

Exhibit A - 2018 RFP Scorecard Template

Summary

Bid Number:	Fill In		
Summary	**Max Score**	**Bid Score**	**Description**
1. Price Scoring	600		
2. Project Development Criteria	100	0	Includes Development team experience, Permitting, Project Finance, Cost Certainty
3. Project Physical Characteristics	130	0	Interconnection, Transmission rights, Resource Certainty (production assessment), Engineering Reliability
4. Project Performance Certainty	120	0	Firmness of Energy, Scheduling, Technological maturity, Online date, Contractual elements
5. Credit Evaluation	50	0	Score based on counterparty's ratio and debt rating
Total Score	1,000	0	

Exhibit A - 2018 RFP Scorecard Template

Thresholds

Bid Number:		Required at Bid Submittal or Short List	Yes	No
1. Proposal satisfies minimum bid quantity and duration criteria:				
Size and Term	Minimum size of 10 MW with minimum 20 year duration.	Submittal		
Qualifying Product	Projects must include all associated Renewable Energy Credits (RECs) and all environmental attributes.	Submittal		
Registered Product	Bidder will be responsible for ensuring RECs are established in WREGIS.	Submittal		
2. Proposal satisfies minimum development criteria				
Site Control	Title, executed lease or executed option agreement for a minimum of 80% of site, with 100% required two weeks prior to final short list.	Submittal and Short list		
Permitting	Refer to attached permitting table attached.	Final Short list		
Project Financing	Demonstrated ability to internally finance project or evidence of good faith commitment from financing institution/financial backer prior to final short listing.	Final Short list		
Equipment costs estimates - PPA	OEM Supply agreements or quote. LTSA quote optional.	Submittal		
Equipment costs estimates - Utility Ownership	OEM and APA+EPC/BOT bid quote. LTSA quote optional.	Submittal		
Tax Credit Eligibility	New Wind projects must include PTC Opinion from qualified accounting firm for PTC eligibility. Solar projects claiming ITC eligibility must demonstrate plan to receive the credit.	Submittal		
3. Proposal satisfies minimum physical characteristics criteria				
Interconnection	Executed System Impact Study Agreement.	Submittal		
Interconnection	Completed Interconnection Facilities Study	Final Short list		
Off System Bidders - BPA Transmission:	Already have long term firm service, PTSA for long term firm service, or CF bridge service agreement transitioning to long-term firm within three years upon near-term, viable upgrades. Alternatively, the project is included in BPA's currently active TSEP process or has requested and been accepted for Individual Study.	Submittal		

Off System Bidders - BPA Transmission:	Has transmission study schedule that allows transmission service commitments by December 31, 2018. For bidders relying on the TSR Study and Expansion Process (TSEP) or Individual Study Process, transmission service commitments will be deemed demonstrated by completion of phase four (Record of Decision issued) or completion of the facilities study respectively.	Final Short list		
On System Bidders - PGE Transmission	Already have service or granted facility plan with approved construction plan targeting completion at least six months prior to COD.	Submittal		
Resource certainty - Historical Data Requirements:	Wind/Solar/Hydro resources must provide a minimum 3-years of data and include an output study from verifiable third-party. Geothermal proposals must have feasibility report completed, based on a year or more of test data from full diameter production wells. Biomass/biogas proposals must come with long-range fuel supply plan with identified, established suppliers and transportation options.	Submittal		
4. Proposal satisfies minimum performance certainty criteria				
Quality of Power	Must be at a minimum unit contingent agreement associated with an identified resource.	Submittal		
Power Scheduling	Off-system resources: Must be integrated by third-party balancing services delivered to PGE using hourly schedules. On-system resources: Must be designated Network Resources.	Submittal		
Technological acceptability - Utility Ownership	Major equipment manufacturer must be on attached preferred vendor list.	Submittal		
Online Date	Online on or before December 31, 2021.	Submittal		
Contractual requirements	Proposed contractual structure, redline or otherwise, must contain provisions related to: Liability Caps, Indemnification, Default/Termination Rights, Performance Guarantees, Remedies for non-performance, and Security/Collateral.	Submittal		
5. Proposal satisfies minimum credit threshold criteria				
Security requirements	PGE will only award contracts to Bidders that have, at a minimum, investment grade credit rating (or with investment-grade guarantors) and can prove that they can provide acceptable performance assurance at time of execution. Investment grade as rated by S&P, Moody's, DBRS and/or Fitch, requires ratings at a minimum must be BBB-, Baa3, BBB low, or BBB- respectively.	Submittal		

Exhibit A - 2018 RFP Scorecard Template

Development Criteria

Development Criteria	Score	Weight	Total	Scoring Rules
2. Project Development Criteria **Max Score = 100**			100	Measures likelihood that project to support proposal will be placed into commercial service on time and on budget
2. Project already in service	0	14	0	Use the following scoring rules for projects that are already in operation: Operating plants should be given a score of 5 points, however this score can be reduced by 1 point if the plant has experienced extended outages, shutdowns or closures during the asset life. For scoring product development from portfolios use the following rules: (1) If product mostly supplied from a specific plant, use that plant for scoring (2) If product supplied from several plants, use the average score from all plants.
For projects not in service proceed with questions below, otherwise go to Section 3				
2.a Permitting status (see permitting attachment)	2	10	20	2 = All project permits and Site Certificate approved. 1 = Major permits approved 0 = Permit process underway, all permits timely acquired consistent with identified thresholds
2.b Experience of Project Team	2	5	10	2 = Successfully developed multiple similar projects in WECC delivered on time without material facility unplanned outages within first year. 1 = Successfully developed multiple similar projects in US. 0 = Successfully developed similar project in US.
2.c Project Financing	1	10	10	1 = Project can be internally financed by developer. Alternatively, project has financing agreement (e.g. primary lender, and tax equity as appropriate) with credible funding source with joint commitment to proceed. 0 = PGE bid award needed to obtain financing (e.g. lender commitment contingent on bid award)
2.d Site Control: Including all rights required for project including access to the project site, easements and resources rights appropriate for the project	1	15	15	1 = Title/Executed lease or options for a minimum of 100% of site 0 = Title/Executed lease or options for a minimum of 80% of site
2.e Cost Certainty - equipment	3	5	15	2 = Pricing guarantee for identified major equipment in addition to executable agreement for prime movers (e.g. turbines, panels) 1 = Executable agreement for prime mover (e.g. turbines, panels) 0 = OEM quotes for prime mover (e.g. turbines, panels) +1 for LTSA or other long-term service quote
All proposals regardless of current online status				
2.f Cost Certainty – Value of Extension	2	10	20	2 = Allows contract extension at original contract price or purchase option at book value or allows for continued operation at cost for benefit of customers 1 = Allows contract extension at price certain or purchase option at known price 0 = Allows for no rights for contract extension or purchase option. Alternatively allows for contract extension or purchase

				option at unknown price (e.g. fair market value)
For ownership proposals regardless of current online status				
2.g Cost Certainty - Milestone payments	1	10	10	1 = Payments at, or under PGE suggested milestone schedule (i.e. payments total less than actual completion percentage prior to completion)
				0 = Payments match with PGE suggested milestones
				-1 = Payments front loaded relative to proposed schedule of values and milestone payment schedule
For PPA proposals regardless of current online status				
2.h Cost Certainty – Pricing Structure	0	5	0	2 = Contract price does not escalate and does not include capacity payment
				1 = Contract price escalating at known and committed escalation rate and does not include capacity payment
				0 = Contract price escalating at market based escalator (e.g. historical CPI) or does include capacity payment

Exhibit A - 2018 RFP Scorecard Template
Physical Characteristics

Physical Characteristics	Score	Weight	Total	Scoring Rules
3. Physical Characteristics Max Score = 130			130	Measures project specific physical attributes for each offer. For scoring physical characteristics from portfolios use the following rules: (1) If product primarily supplied from a specific plant, use that plant for scoring; (2) If product supplied from several plants, use the average score from all plants.
3.a Interconnection Rights	5	10	50	5 = Executed LGIA or project in operation.
				4= Tendered LGIA, in Negotiations.
				3 = Executed optional Engineering and Procurement Agreement (E and P) or procurement agreement for long-lead interconnection items if applicable.
				2 = Completed Interconnection Facilities Study (must be completed prior to final short list).
				1 = Completed Interconnection System Impact Study.
				0=Executed System Impact Study Agreement.
3.b.1 Long Term Firm Transmission Rights on BPA's transmission	4	10	40	4 = Existing long-term firm rights to BPAT.PGE POD.
				3 = Existing long-term firm rights confirmed by transmission provider to be redirectable to PGE's system.
				2 = Executed PTSA for existing firm transmission to BPAT.PGE POD.
				1 = PTSA agreement executed for identified upgrades. PTSA contains offer of conditional firm-bridge service that converts to long-term service upon completion of upgrades. Facility upgrades to be completed no later than three years after COD.
				0 = Project included in the currently active round of TSEP or has requested and been accepted for Individual Study.
3.b.2 Long Term Firm Transmission Rights on PGE's Transmission	0	10	0	4 = Executed Interconnection Agreement with Network Resource Integration Service or existing long-term firm rights.
				2 = Tendered Interconnection Agreement with Network Resource Integration Service or executed Construction Agreement.
				1 = Completed Facility Study.
				0 = Completed System Impact Study.
3.c Projects Subject to BPA Oversupply Management Protocol	0	-10	0	1 = Project subject to BPA Oversupply Management Protocol.
				0 = Project not subject to BPA Oversupply Management Protocol.
3.d Remedial Action Scheme Projects Subject to (RAS)	1	10	10	1 = PGE able to use resource as a credit for its obligation to support AC intertie RAS.
				0 = No RAS.
3.e Engineering Reliability	5	2	10	For all project types (maximum of 5 points)
				1 = PGE is able to influence in maintenance and availability

				decisions impacting reliability (0 if no influence). 2 = The experience and expertise of O&M operator (<5 years=0, 5-9 years=1, >10 years=2). 1 = The owner and/or operator is supported by local or centralized engineering staff (0 otherwise). 1 = The seller has an established relationship with prime mover vendor including vendor support through a service agreement (<5 years=0, 5-9 years=.5, >10 years=1).	
Resource Specific Issues					
3.f Resource Certainty	**Wind/Solar/Hydro Resources**				Select Resource type for 4.a
	4	5	20	4 = 7+ years data. 3 = 6-years data. 2 = 5-years data. 1 = 4-years data. 0 = 3-years data (threshold). 2 = Wind project is a staged build-out of an adjacent project (assumes adjacent project has at least 7 years' wind data and the adjacent project has a similar wind microclimate to the original project).	
	Geothermal Resource				
	0	20	0	1 = Production and injections wells for the project drilled and completed. 0 = Feasibility report completed, based on >1 year of test data from full diameter production wells.	
	Biomass/Biogas – Project Fuel Supply				
	0	5	0	4 = Firm access to multiple fuel sources for 100% or greater of need, with ability to store fuel on site and options for fuel transportation. 3 = Firm access to multiple fuel sources for 100% or greater of need. 2 = Have executed long-term fuel supply contract for minimum of 60% of need with ability to store fuel on site and options for fuel transportation. 1 = Have executed long-term fuel supply contract for minimum of 60% of need with plan for remaining need. 0 = Have fuel supply plan with identified, established suppliers and transportation options.	

Exhibit A - 2018 RFP Scorecard Template

Performance Certainty

Performance Certainty	Score	Weight	Total	Scoring Rules
4. Performance Certainty Max Score = 120			120	Measures project specific commercial and delivery attributes for each offer.
4.a Quality of Power - Firmness of Energy	2	10	20	2 = Backed by physical resources or system with resupply obligation for curtailments or outages including make whole provisions for bundled RECs.
				1 = Backed by physical resources or system with finite resupply obligation for curtailments or outages including finite make whole provisions for bundled RECs.
				0 = Finite resupply obligation without make whole provisions for RECs.
4.b Quality of Power - Scheduling Period Commitment	2	5	10	2 = Weekly or greater in scheduling.
				1 = Pre-schedule.
				0 = Hourly.
4.c Online Date	2	10	20	0 = prior to 12/31/2019.
				2 = After 12/31/2019 and prior to 12/31/2020.
				1 = After 12/31/2020.
4.d Guarantee Available Factor	2	5	10	2 = Minimum mechanical availability agreement of 97% or greater for any two out of three calendar years on a rolling basis.
				0 = No stated minimum mechanical availability commitment.
4.e Liability Cap Contractual Terms and Conditions Redlines	6	2	12	6 = 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.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.
4.f Indemnification Contractual Terms and Conditions	6	2	12	6 = 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.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or

				cost.
4.g Default & Termination Contractual Terms and Conditions	6	2	12	6 = 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.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.
4.h Security and Collateral Contractual Terms and Conditions	6	2	12	6 = 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.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.
4.i Performance Guarantees and Remedies of Non-Performance Contractual Terms and Conditions	6	2	12	6 = 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.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.

Exhibit A - 2018 RFP Scorecard Template

Credit

Credit	Score	Weight	Total	Scoring Rules	
5. Credit Evaluation Max Score = 50			50	**Score based on Bidder, not Guarantor**	
5.a PGE ratio analysis score	10	2	20	10=Credit score of 10	5=Credit score of 5
				9=Credit score of 9	4=Credit score of 4
				8=Credit score of 8	3=Credit score of 3
				7=Credit score of 7	2=Credit score of 2
				6=Credit score of 6	1=Credit score of 1
5.b Bond Rating	10	2	20	10=Aaa/AAA	
				8=Aa/AA	
				6=A/A	
				4=Baa/BBB	
				2=Baa-/BBB-	
				0=Below BBB- or not rated	
5.c Tangible Net Worth	10	0.5	5	10 >1,000mm	5=600mm-501mm
				9= 1000mm-901mm	4=500mm-401mm
				8= 900mm-801mm	3=400mm-301mm
				7= 800mm-701mm	2=300mm-101mm
				6= 700mm-601mm	1= <100mm
5.d Corporate Structure	5	1	5	5=Publicly Traded	
				4=Publicly Traded subsidiary	
				3=Private Corporation	
				2=Private LLC	
				1=Sole Proprietorship/Partnership	

Permitting Timing Guidelines

Permits (if applicable to the specific project)	**Wind**	**Solar**	**Geothermal**	**Hydro / Pumped Storage**	**Biomass**
Detailed Plan for Obtaining All Major Permits (w/schedule)	Bid	Bid	Bid	Bid	Bid
State/local siting permit (e.g. site certificate, conditional use permit)	Award	Award	Award	Bid	Award
Federal siting permit (e.g. NEPA Record of Decision for construction*, FERC License or final EIS from FERC) **This does not include NEPA for an Eagle Take Permit*	Award	Award	Award	Bid	Award
Air quality permit (e.g. ACDP)	N/A	N/A	N/A	N/A	Award
FCC permit	Award	Award	Award	Award	Award
FAA permits	CP	Award	N/A	Award	Award
Airspace and Obstacle Evaluation Analysis	Bid	N/A	N/A	N/A	N/A
Water rights	N/A	N/A	Award	Bid	Award
Wastewater discharge permit (e.g. NPDES, WPCF)	N/A	Award	Award	N/A	Award
Construction Permits (NPDES - 1200 C, etc.)	Award	Award	Award	Award	Award
Removal Fill Permits (DSL and Corp)	Award	Award	Award	Award	Award
Eagle surveys finished or nearly finished	Bid	Bid	Bid	Bid	Bid
Federal ESA surveys completed	Bid	Bid	Bid	Bid	Bid
Cultural Resources Surveys	Bid	Bid	Bid	Bid	Bid
Tribal coordination (Traditional Use Studies. Traditional Cultural Properties)	Bid	Bid	Bid	Bid	Bid
Misc: Dikes, Scenic Areas, Local Requirements	Award	Award	Award	Award	Award

Key:					
Bid - Approved by bid submittal date					
Award - Approved by bid award date					
CP - Approved as a condition precedent in the definitive agreement(s)					
N/A - Not applicable					

2018 Renewable RFP - Major Permit Identification by Technology

Wind	Solar	Geothermal	Hydro / Pumped Storage	Biomass
Federal and State and Local Permitting	Federal and State and Local Permitting	Federal and State and Local Permitting	Federal and State and Local Permitting	Federal and State and Local Permitting
		Water Rights	Water Rights	Air Permit
		Wastewater Permit	Construction Permits	Water Rights
			Removal Fill Permits, if appropriate	Wastewater Permit

Local permits include Conditional Use Permit and Zoning Permit

2018 Renewable RFP Major Equipment Preferred Vendors

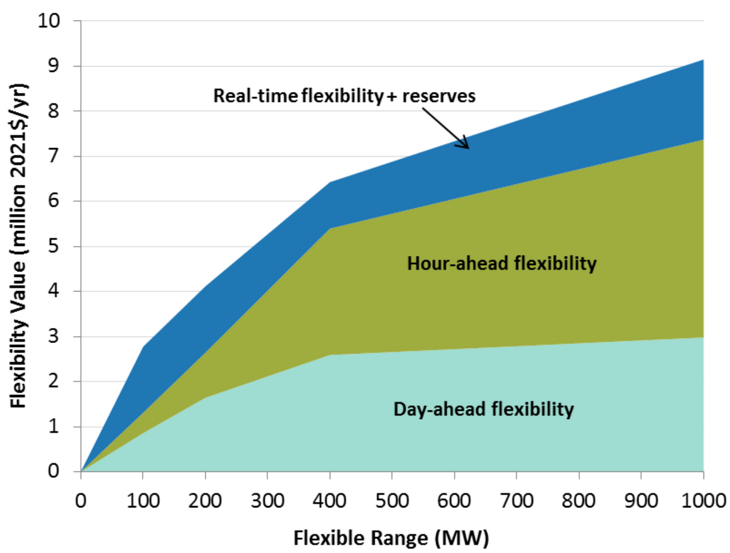
Substation Main Power Transformer	GSU Pad-mount Transformers	Photovoltaic Inverters	Photovoltaic Modules	Wind Turbine Generators
ABB, Varennes, Canada shop	ABB	SMA	JA Solar	General Electric
ABB, St. Louis, Missouri shop	CG Power Systems USA	Power Electronics	Trina Solar	Siemens Gamesa
ABB, Bad Honnef, Germany shop	General Electric	TMEIC	Jinko	Vestas
ABB, South Boston, Virginia shop	Cooper Power Systems	Eaton	Canadian Solar	Nordex/Acciona
HICO, ChangWon, South Korea shop	Siemens	General Electric	Hanwha Q-Cells	
Hyundai, Montgomery, Alabama shop	Pacific Crest Transformers	ABB	First Solar	
Hyundai, Ulsan, South Korea shop			Sunpower	
Smit, Nijimegen, The Netherlands shop			Kyocera	
SPX Waukesha, Waukesha, Wisconsin shop			LG	
EFACEC, Arroteia, Portugal shop			REC	
Siemens, Guanajuato, Mexico shop				
GE Prolec, Monterrey, Mexico shop				
Shihlin, Taipei, Taiwan shop				

Exhibit B – Flexibility

B.1 Flexibility value functions

In preparation for the evaluation of offers, PGE conducted a series of simulations with the ROM tool to isolate the flexibility benefits of perfectly flexible products available in various time frames (day-ahead, hour-ahead, and real-time[1]) and at various sizes (100MW, 200MW, 400MW, and 600MW) in a 2021 test year. For each simulation, the resource operational value was calculated as the annual operational cost difference between the PGE resource fleet with the perfectly flexible resource and the PGE resource fleet without the perfectly flexible resource. The flexibility value was isolated by subtracting the market revenues that the resource was capable of providing if it had dispatched to market in all hours from the total operational value obtained by optimizing its dispatch in coordination with the PGE resource fleet. This exercise yielded a set of functions that could be used to approximate the flexibility value associated with each offer in each stage according to its "flexible range" – the portion of the resource capacity that could be approximated as perfectly flexible in each stage. These functions are shown in the figure below.

Figure 1. Flexibility value functions by stage and size



The annual flexibility values shown in the above figure were allocated to each season based on the seasonal distributions of the flexibility values identified by

[1] Real-time flexibility was bundled with the ability to provide load following, regulation, spinning, and non-spinning reserves, since the incremental value of these ancillary services was found to be relatively small.

ROM. The resulting allocation factors, which are summarized in the table below, were used to obtain monthly flexibility values by stage and flexible range.

Table 3. Flexibility value seasonal allocation factors

Stage	Q1	Q2	Q3	Q4
Day-ahead flexibility	25%	34%	30%	10%
Hour-ahead flexibility	19%	34%	33%	13%
Real-time flexibility + reserves	27%	23%	39%	12%

Flexibility values were assumed to escalate at inflation through the analysis horizon.

B.2 Flexible ranges

For each offer, flexible ranges are calculated for the day-ahead, hour-ahead, and real-time stages based on the operating characteristics of the resource. The flexible range calculation is conducted on a monthly basis over the full duration of the resource in the PGE portfolio. This calculation depends on whether the offer reflects an energy-limited or non-energy-limited resource. Energy-limited resources are those with a fixed amount of energy that much be used over a stated length of time – in other words, they behave like hydro resources. Non-energy-limited resources are all other resources that do not have this energy-driven constraint – they behave more like thermal resources.

B.3 Energy-limited

In the flexibility evaluation, each energy-limited resource is characterized by its minimum (p_m^{min}), maximum (p_m^{max}), and average (p_m^{avg}) dispatch level by month throughout the resource duration. Flexible ranges may also be limited by a fixed amount in each stage (f_k). In month m and stage k, the flexible range for an energy-limited resource is:

$$\min\left[2\left(p_m^{max} - p_m^{avg}\right), 2\left(p_m^{avg} - p_m^{min}\right), f_k\right]$$

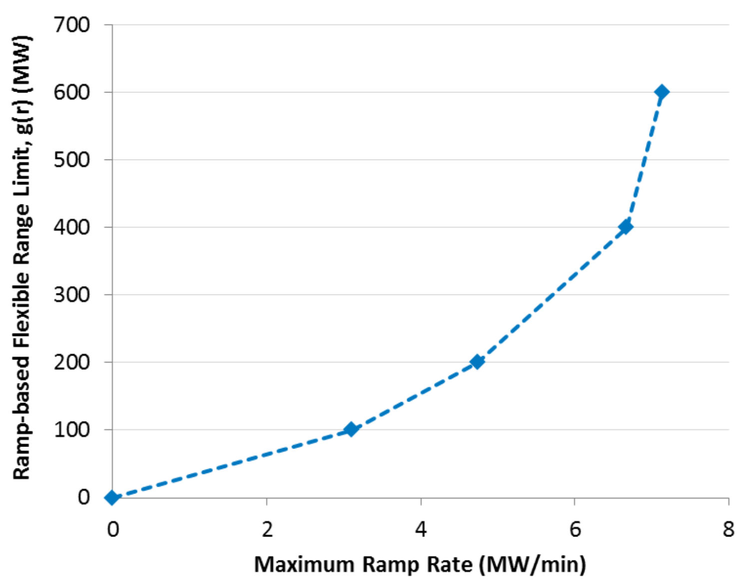
B.4 Non-energy-limited

Non-energy-limited resources are characterized in the flexibility evaluation by their monthly maximum output (p_m^{max}), minimum output (p_m^{min}), availability in each stage (a_{km}), ability to be re-comitted in each stage (c_k), ability to redispatch in each stage (d_k), and maximum ramp rate (r). The availability in a given month is defined as the fraction of hours that the resource is committed (i.e., has non-zero output) in that month in the AURORA dispatch simulation. If a resource can be re-committed and redispatched in a given stage, then its flexible range reflects the full capacity range between its minimum and maximum output regardless of its availability. However, if the commitment is fixed in a given stage (due to fuel or operational constraints) but the resource can be redispatched, then the flexibility range is scaled by the availability in order to reflect the probability that the resource has been committed in a prior stage. The flexibility range is also limited by a function, $g(r)$, of the maximum ramp rate, which is discussed further below. In month m and stage k, the flexible range for a non-energy-limited resource is:

$$\min\left[d_k\left(p_m^{max} - p_m^{min}\right)\left[c_k + (1 - c_k)a_{km}\right], g(r)\right]$$

The ramp rate-based function, $g(r)$, limits the flexible range based on the ramping capability of the resource. In the day-ahead and hour-ahead stages, this function was determined by calculating the ramping capability needed to meet 95% of all ramps experienced by the perfectly flexible resource in the ROM simulation. Because units ramp between hourly schedules over the last 10 minutes of each hour and the first 10 minutes of the following hour, the function assumes that the resource must be capable of meeting simulated hourly ramps over a 20-minute period. The resulting function is shown below.

Figure 2. Ramp-based flexible ramp limit, *g(r)*, for day-ahead and hour-ahead stages



The ramp-based limit on the flexible range for real-time flexibility and reserves is equal to 10 minutes times the MW/min ramp rate to reflect the approximate time scale of modeled subhourly dispatch needs and reserve requirements.

B.5 Portfolio flexibility values

The flexibility value in the portfolio modeling stage is calculated using the same methodology and the same flexibility value functions used to evaluate specific resources. In this exercise, the flexible range in each month associated with the portfolio is the sum of the flexible ranges of the component resources in the corresponding month. Because the flexibility functions are sub-linear, the monthly portfolio flexibility value is less than the sum of the monthly flexibility values of the component resources. This approach therefore captures the declining marginal value of flexible resources in PGE's resource portfolio, a phenomenon identified in the energy storage evaluation and discussed in Chapter 8 of the 2016 IRP. Within the portfolio flexibility value assessment, PGE will recognize the flexibility value effects of the bilateral capacity agreements executed by PGE in Q1 2018 and described in the 2016 IRP Update.

Exhibit C – Aurora Dispatch

As discussed in PGE's 2016 IRP, AURORAxmp allows PGE to perform fundamental analysis of the western power markets under various assumptions and test the performance of candidate resource portfolios in those environments. PGE uses the net present value of revenue requirements (NPVRR) to summarize the expected cost of portfolios. The NPVRR includes the fixed and variable costs associated with operating the respective resources, as well as the net market revenue or expense associated with net sales or purchases in the portfolio. PGE evaluates portfolio risk according to two primary categories:

1. Reliability risk: Serves as a threshold for portfolio design; and,
2. Deterministic risk: Referred to above as "futures."

To evaluate the variable benefits of the candidate resources in the bilateral capacity acquisition initiative, PGE used AURORAxmp consistent with the Integrated Resource Plan (IRP) methodology. This methodology includes:

1) Western Electric Coordination Council (WECC) Capacity Expansion
2) Generate Market Power Prices
3) Compute the "Value" of all candidate resources

WECC Capacity Expansion: PGE used the three capacity plans developed under various carbon price futures in the 2016 IRP. PGE used Wood McKenzie's database for information regarding the existing resources in WECC. It was not necessary to execute new long-term capacity expansion studies as long-term market fundamentals have not moved significantly enough to justify the effort required to perform long-term studies.

Market Power Prices*:* Using the applicable WECC capacity plan, hourly Mid-Columbia power price curves until year 2050 under 27 various futures were generated. The futures were designed to study impacts of three factors on power pricing: carbon pricing, natural gas pricing, and regional hydro availability. More detail for each factor is shown below.

Carbon pricing: PGE used three carbon price estimates: zero carbon prices, reference carbon prices, and high carbon prices. Consistent with the IRP, PGE used Synapse's forecasts for the reference and high carbon pricing.

Natural Gas pricing: PGE used three natural gas pricing scenarios: Low, reference and high. Consistent with the 2016 IRP Update data source assumptions, the trading curve was used until 2021 for all three scenarios.

Regional hydro availability: PGE used three regional hydro scenarios: low, reference and high. The reference case value is the average of historical hydro estimates provided by Wood Mackenzie. For low and high values, consistent with the 2016 IRP Update, PGE adjusted forecasted hydro volumes by ten percent.

PGE simulated all combinations of carbon price, gas price and regional hydro availability scenarios to create 27 futures.

Exhibit D – Portfolio Construction

Candidate portfolios will consist of executable combinations of all offers. The total resources selected must meet the energy target identified in Commission Order No. 18-044. PGE will optimize portfolio selection with the following two-step processes:

1. Select the starter resource. There will be an optimal candidate portfolio based on each resource.
2. Use the Excel solver to select additional resources to add to the starter resource. Excel will select resources under different optimization routines such as minimizing the deviation from the target MWa energy addition in 2021 or total net costs.

The first optimization routine consists of an optimization problem to minimize the difference (delta) between a portfolio's total energy and the energy target in 2021. The optimized portfolio under the first optimization routine will be calculated using the following formula:

$$f(\underline{x}) = \left| TG_t - \sum_{i=1}^{n} E_{t,i} \cdot \underline{x} \right|$$

$$\min_{\underline{x}} f(\underline{x})$$

$$s.t.\ \underline{x}\ is\ binary$$

where:

$\underline{x}$: A binary vector representing resource selection in a portfolio (0 represents exclusion, and 1 represents inclusion)

$E_{t,i}$: Energy of the resource *i* for the year *t*

TG_t : Energy target of the year *t*

t : Year 2021

i : Resource index

The second optimization routine set up an objective function to minimize a portfolio's total present value net cost. The optimized portfolio under the second optimization routine will be calculated using the following formula:

$$f(\underline{x}, y_t) = \sum_t^T P_t \cdot \{TC_{t,i} \cdot \underline{x} + F_t . y_t\}$$

$$\min_{\underline{x}, y_t} f(\underline{x}, y_t)$$

$$s.t.\ \underline{x}\ is\ binary$$

$$\text{and }\ \underline{x} \cdot E_{t,i} + y_t \geq TG_t$$

where:

$\underline{x}$: A binary vector representing resource selection in a portfolio
(0 represents exclusion, and 1 represents inclusion)
y_t : Amount of the fill resource needed for the year t
$TC_{t,i}$: Total net cost of the resource i for the year t
TG_t : Energy target of the year t
$E_{t,i}$: Energy of the resource i for the year t
F_t : The fill resource's total net cost
(standardized by the fill resource's name plate capacity)
P_t : Present value factor
t : The beginning of the period
T: The end of the period

To supplement the optimized portfolios, PGE will also develop all possible portfolio permutations with total energy ranging from 75MWa to 125MWa in 2021 and will advance the top 50^{th} percentile of these portfolios to portfolio evaluation. Performance in the 50^{th} percentile screen will be measured on the basis of present value net cost, with the top portfolios achieving the lowest present value net cost.

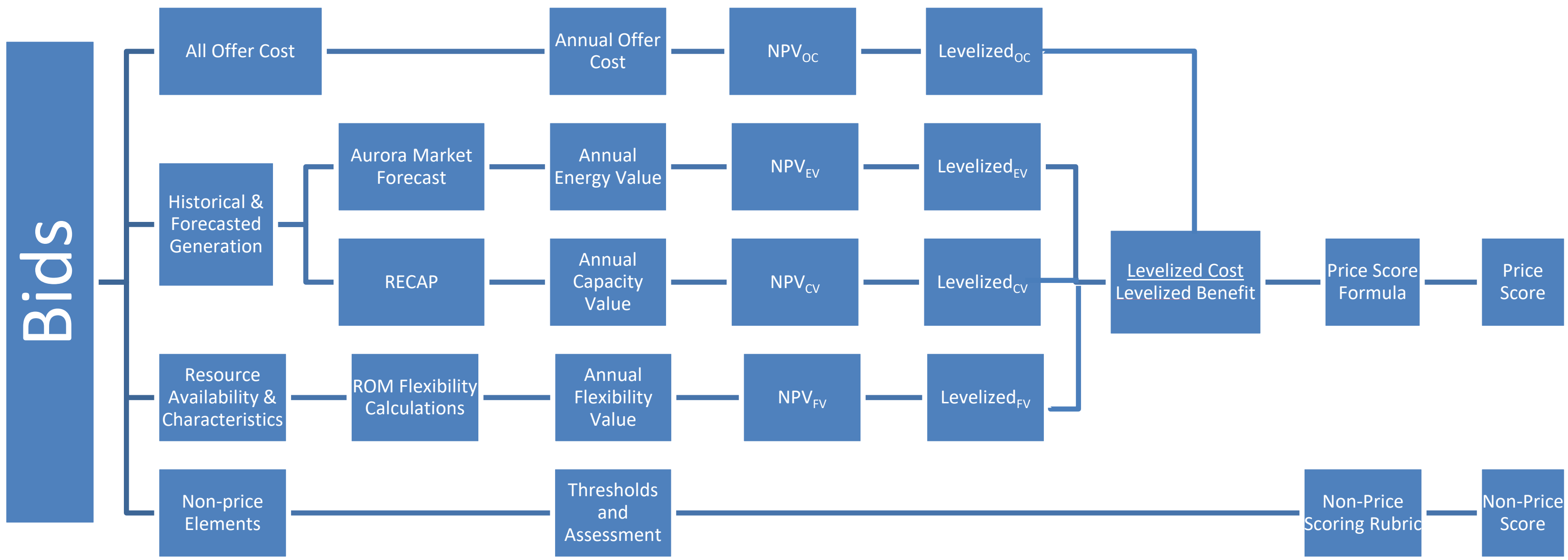
Portfolio Term and Size Normalization

For portfolio analysis, resources will be term and size normalized to match the energy target identified:

- To term normalize for resources with shorter duration (e.g. PPA for 20 years), we will fill with the real levelized cost of an appropriate specific resource of like size for the remaining planning horizon.
- To size normalize, any difference in size between the offers' total energy and the targeted energy need will be effectively filled in by the remaining specific fill resource.
- The specific resource used to size and term normalize reflects the cost and performance of new resources informed by the initial short list.

Filling with costs associated with new resources will correctly account for the risks associated with the energy target identified in Commission Order No. 18-044. We will calculate a total portfolio cost based on the AURORA dispatch of the candidate portfolios across futures including the reference case of carbon price, natural gas price, and hydro availability. In addition, we will calculate risk as the standard of deviation of the total portfolio present value net cost of candidate portfolios across the futures. Candidate portfolios will be ranked in order of increasing costs and risks. After the initial analysis, portfolio results will be stress-tested under multiple energy targets and qualifying facility planning scenarios.

Exhibit E – Scoring Process Flow



Attachment B

STAFF'S INITIAL COMMENTS
FROM PUBLIC UTILITY COMMISSION
OF OREGON DOCKET NO. AR 600

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 600

In the Matter of Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources.	STAFF'S INITIAL COMMENTS

I. INTRODUCTION

The Public Utility Commission of Oregon Staff (Staff) submits these initial comments in this docket. These initial comments are limited in scope and are intended to respond to a Commission request that Staff provide analysis relating to independent evaluator (IE) costs during the public comment period.[1] Staff plans to file additional comments prior to the close of the public comment period on June 15, 2018.

II. BACKGROUND

Prior to issuing notice of the proposed rulemaking, the Commission indicated that "we wish to see more data and information from Staff regarding IE costs in a variety of scenarios. As discussed in the [March 6, 2018] workshop, we believe that part of the rationale for the proposal to allow exemption from the IE retention requirement in the case of an RFP that does not contemplate electric company ownership of resources is cost savings. We expect Staff to provide analysis to us during the public comment portion of this proceeding on IE costs."[2]

Accordingly, Staff issued information requests to determine the historic cost of IEs in procurements conducted under the Commission's Competitive Bidding Guidelines. In response, two of the Joint Utilities were able to provide total IE costs for ten requests for proposals (RFPs).

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[1] See Order No. 18-087, available at: http://apps.puc.state.or.us/orders/2018ords/18-087.pdf.

[2] Order No. 18-087.

Staff's analysis is discussed below. Additional cost information may be included in additional comments filed by Staff.

II. Summary Analysis

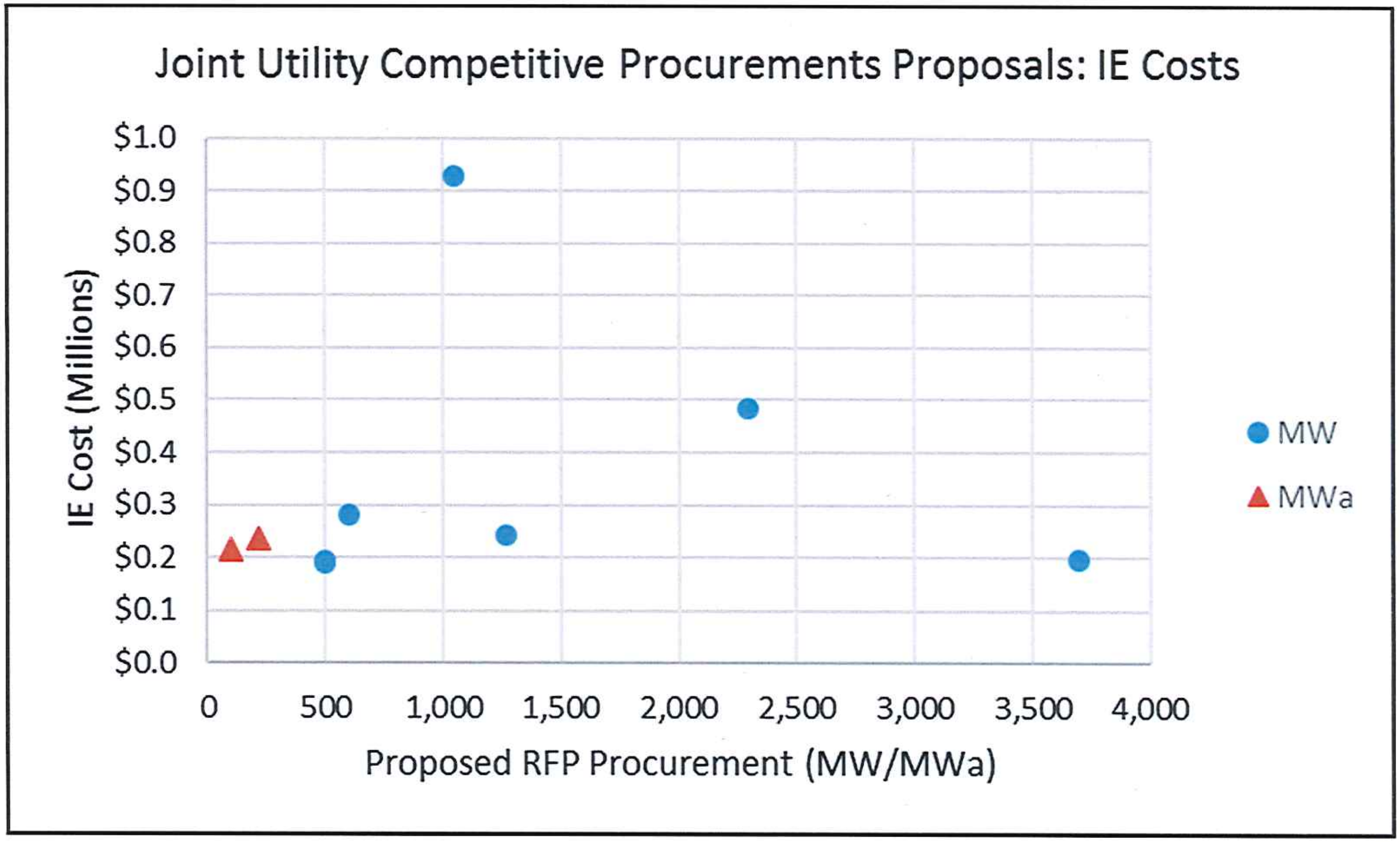
Staff reviewed cost data provided for ten RFPs that involved the services of an IE. The RFPs have issue dates ranging from 2007 to 2018. Of the ten RFPs, six of the RFPs were exclusively for renewable energy sources. Staff notes that the IE costs associated with the procurement of the Carty Generating Station (PGE's 2012 Power Supply Resources RFP) were combined with the IE costs associated with PGE's 2012 Renewable RFP as the same IE was used for both RFPs. For the purposes of this analysis, the total IE cost for the two RFPs are treated as one procurement. The total reported cost of an IE's services for the nine RFPs, without taking into account what has been recovered through customer rates, ranges from $190,000 to $929,000. The average IE cost of all the RFPs, with the inclusion of the RFP associated with Carty, is $329,000. Without including the Carty RFP, the average IE costs of the eight RFPs is $254,000. As seen in Table 1 and Table 2 below, the relationship between procurement size and IE cost is not direct. The RFP with the largest-issued procurement size had the lowest IE costs of the nine RFPs under review. To note, the three renewable RFPs are reported in average megawatts. These three procurements were calls for renewable resources in general. It would be inappropriate to convert the average megawatts to a nameplate capacity relating to any one given renewable resource type. For detail beyond the summaries in the tables below. see the attached utility responses to the related information requests.[3, 4]

[3] PGE's response to OPUC Information Request No. 001, Attachment A.
[4] PacifiCorp's response to OPUC Information Request No. 001, Attachment B.

Table 1: Joint Utility IE Cost Summary

Project	1	2	3	4	5	6	7	8	9	10
Type	Thrm	RE	RE	RE	Thrm	Thrm	Thrm	RE	RE	RE
Size	2290 MW	218 MWa	500 MW	500 MW	3700 MW	597 MW	1050 MW	101 MWa	100 MWa	1270 MW
Year	2007	2008	2008	2009	2009	2012	2012	2012	2016	2017
IE Cost	$0.5 M	$0.2 M	$0.2 M	$0.2 M	$0.2 M	$0.3 M	$0.9 M		$0.2 M	$0.2 M

Table 2: Joint Utlitity Competitive Procurements: Independent Evaluator Costs



III. Cost Drivers for Independent Evaluator Work

Staff has considered the various factors that can affect IE cost. As noted above, the size of the procurement does not appear to be a defining factor. However, there are other factors that can drive IE costs up or down. The type of procurement, for example, whether the resource is base load or renewable, can have variable impact on IE costs. Base load resource procurement often entails specific unit comparisons through complex modeling. Renewable resource procurement, specifically solar energy resources, require additional analysis related to distribution infrastructure. The complexity of the RFP design process, and the degree to which an IE is involved in that process, can lead to more or less material for an IE to review and evaluate before an RFP is approved. The number of proposals received in response to an RFP will affect the amount of time the IE will need to spend in review. The degree to which the IE needs to interact with bidders can affect the costs involved. Similarly, the amount of time the IE may need to be available to engage with the Commission or to be available during contract negotiations can affect the cost associated with a procurement. Finally, Staff notes that the IE's responsibility in relation to high-end modeling, involves at a minimum, analysis and review of the production-cost and transmission modeling inputs and outputs. In some instances, the IE may need to run its own modeling in addition to reviewing the utility's model input and output, which can further increase IE costs.

This concludes Staff's Initial Comments.

Dated at Salem, Oregon, this 13th of June 2018.

Thomas Familia
Senior Utility Analyst
Energy Resources & Planning

AR 600 PGE Response to OPUC IR 001
AR 600 Attachment A

RFP	2018 Renewable RFP	2016 Renewable RFP	2012 Power Supply Resources RFP	2012 Renewable RFP	2008 Renewable RFP
i) RFP Name;	Portland General Electric Company Request for Proposals Renewable Energy Resources	Portland General Electric Company Request for Proposals Renewable Energy Resources	Portland General Electric Company Request for Proposals Power Supply Resources	Portland General Electric Company Request for Proposals Renewable Energy Resources	Portland General Electric Company Request for Proposals Renewable Energy Resources
ii) RFP Issue Date;	Not Yet Issued	Not Issued	June 8, 2012	October 1, 2012	April 23, 2008
iii) Associated OPUC Docket Number;	UM 1934	UM 1773	UM 1535	UM 1613	UM 1345
iv.a) Procurement size (MW), if identified in the RFP	100 MWa	100 MWa	200 MW flexible, year-round capacity resources, 200 MW of bi-seasonal capacity contracts, 150 winter peaking capacity contracts and/or 300-500 MW CCCT Targeted	101 MWa	218 MWa
iv.b) Resource size acquired, if any, based on final result of RFP process;	0 MWa	0 MWa	220 MW Reciprocating Engine, 440 MW CCCT	98 MWa	0 MWa
v) Type of generation asset sought in the RFP;	RPS Eligible Renewable Resources	RPS Eligible Renewable Resources	SCCT; Reciprocating engines; Pumped storage hydro; Hydro with pond capability; Energy storage; CCCT	RPS Eligible Renewable Resources	RPS Eligible Renewable Resources
vi) Name of independent Evaluator selected and approved by the Commission;	Bates White	Accion Group	Accion Group		Accion Group
vii) Description of how Independent Evaluator services were to be compensated by Company under its contract;	Time and Materials	Time and Materials	Time and Materials		Time and Materials
viii) Total Cost to compensate Independent Evaluator;	Ongoing	$214,293	$928,718		$233,658
ix) Amount of total cost to compensate Independent Evaluator recovered through customer rates.	$0	$0	$430,152		$233,658

Oregon Independent Evaluator(s) Summary
PacifiCorp - Request for Proposals for Generation Resources
As at May 11, 2018

subpart (i)	*subpart (ii)*	*subpart (iii)*	*subpart (iv)*	*subpart (v)*	*subpart (vi)*	*subpart (vii)*	*subpart (viii)*
Request for Proposals (RFP) Name	**RFP Issue Date**	**Public Service Commission of Oregon (OPUC) Docket Number**	**Procurement Size (megawatts (MW))** (1)	**Type of Generation Resource(s) Sought**	**Name of Independent Evaluator (IE)**	**How IE was compensated by PacifiCorp**	**IE Total Cost**
2012 RFP	5-Apr-07	UM-1208 / UM-1285	2012 - 600 MW to 940 MW 2013- 750 MW 2014 - 250 MW to 600 MW	All resources accepted including benchmark bids; tied to PacifiCorp's 2004 Integrated Resource Plan (IRP)	Boston Pacific, Company, Inc. (RFP review) Accion Group (RFQ review)	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	Accion Group: $190,398 Boston Pacific Company, Inc.: $292,979
2008 All Source RFP (re-issued in 2010 as All Source RFP)	2-Oct-08 (re-issued 2-Dec-09)	UM-1360	2012 - 1,300 MW 2016 - 2,400 MW	Base Load and Intermediate Load generating assets sold via Asset Purchase and Sale Agreements (APSA), Tolling Service Agreements (TSA) and purchases of existing assets] represents nearly 6,500 MW	Boston Pacific, Company, Inc. (RFP review) Accion Group (RFQ review)	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	$195,395
2008R-1 Renewables RFP	6-Oct-08	UM-1368	500 MW of system-wind renewable resources (~5,000 MW offered)	Renewables (wind) via Build-Own-Transfer (BOT), Power Purchase Agrements (PPA), and 50 percent BOT / 50 percent PPA	Boston Pacific, Company, Inc.	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	$190,341
2009 RFP for Supply-side Renewable Resources (Expedited Treatment Requested)	9-Jul-09	UM-1429	Up to 2,000 MW by 2013	All renewable resource types	Boston Pacific, Company, Inc.	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	$192,583
2016 All-Source	4-Apr-12	UM-1540	Up to 597 MW Baseload	All-source / No benchmark. Currant Creek Site Included	Boston Pacific, Company, Inc.	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	$282,113
2017R RFP	27-Sep-17	UM-1845	1,270 MW	Wind resources only	Bates White Economic Consulting (formally Boston Pacific Company, Inc.)	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 and OPUC Order 14-149 in Docket UM-1182	$243,184

Notes:

(1) Procurement size (MW), if identified in RFP, and size required, if any, based on final results of RFP process