ORDER NO. 14 149

ENTERED APR 30 2014

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1182

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation Regarding Competitive Bidding.	ORDER

DISPOSITION: COMPETITIVE BIDDING GUIDELINES MODIFIED, DOCKET CLOSED

I. SUMMARY

In this order, we conclude our examination of the competitive bidding guidelines. We adopt minor changes to Guideline 10(d) to explicitly direct the Independent Evaluator (IE) to consider seven risk items the parties identified for comparing the acquisition of a utility-owned resource to purchasing power from an independent power producer (IPP).

We also adopt a requirement, as requested by Northwest & Intermountain Independent Power Producers Coalition (NIPPC), that the utilities file an application with the Commission seeking acknowledgment of their final shortlist of bidders. This requirement is included in revised Guideline 13, as shown below.

II. INTRODUCTION

Procedural Background

We re-opened this docket to further examine the potential bias in the utility resource procurement process that favors utility ownership of generation assets over power purchase agreements (PPAs) with third parties.[1] We previously recognized that a bias exists due to the nature of ratemaking, which provides a utility the opportunity to earn a return on plant investments but not on PPAs.[2] In this proceeding we have focused on reducing the bias through our competitive bidding guidelines.

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[1] Third parties may propose different contract structures including fixed or variable price PPAs, tolling service agreements, or lease agreements.

[2] *In the Matter of an Investigation to Address Potential Build-vs.-Buy Bias*, Docket No. UM 1276, Order No. 11-001 at 2, 5 (Jan 3, 2011).

In this final phase of these proceedings, we asked parties to comment on the IE's analysis under Competitive Bidding Guideline 10(d).[3] Guideline 10 describes the role of the IE and the utility in the request for proposals (RFP) process, and section (d) specifically states that the IE will independently score the utility designated benchmark resource[4] and all or a sample of bids to determine whether the initial and final shortlists are reasonable. Guideline 10(d) further states that the IE will evaluate the unique risks and advantages associated with a utility-built benchmark resource, including the regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected for the RFP.[5]

In an earlier phase of this docket, parties identified twelve items of interest that could potentially be considered by the IE to evaluate and compare the unique risks and advantages of utility benchmark resources as compared to purchasing power from IPPs. In Order No. 13-204, we examined four of those potential risk items and adopted changes to address two of them: (1) construction cost over-runs and (2) wind capacity factor error.[6] We directed the IE to provide a more comprehensive accounting of the risks and benefits to ratepayers for construction costs of utility-owned resources. We also required utilities to use qualified and independent third-party experts to review the expected wind capacity factor for all projects on the shortlist.

In this last phase of the proceeding, we asked parties to address the remaining eight risk factors. These factors are: (1) changes in forced outage rates curve; (2) end effect; (3) environmental regulatory risk; (4) increases in fixed operation and maintenance (O&M) costs; (5) capital additions; (6) changes in allowed return on equity (ROE); (7) verify output, heat rate, and power curve; and (8) construction delays.

Comments were submitted by NIPPC; PacifiCorp, dba Pacific Power; Portland General Electric Company (PGE); Idaho Power Company; and Commission Staff.

III. RISK ITEMS

A. Overview of Parties' Comments

The utilities and Commission Staff are generally satisfied with the IE's current analysis, and do not believe that significant revisions are needed to the IE's instructions. The utilities explain that many of the risk factors are already included as a line item in their benchmark bids, that PPA bids are also evaluated for these items, and that the IE checks all short-listed bids for reasonableness.

[3] *Id.* at 6.
[4] A benchmark resource is a utility's site-specific, self-build resource. Order No. 06-446 at 5. A utility-owned resource may also be bid as an asset purchase and sale agreement (APSA).
[5] *In the Matter of an Investigation Regarding Competitive Bidding,* Docket No. UM 1182, Order No. 06-446 Appendix A at 3 (Aug 10, 2006).
[6] *In the Matter of an Investigation Regarding Competitive Bidding,* Docket No. UM 1182, Order No. 13-204 (Jun 10, 2013). We declined to make changes to address two other risk items, heat rate degradation and counterparty risk.

Nonetheless, for the following factors, at least one party suggested that the IE verify that the value included in bids is reasonable: (1) changes in forced outage rates over time; (2) end effect; (3) environmental regulatory risk; (4) increases in fixed O&M costs over time; (5) capital additions over the resource life; and (7) verify output, heat rate, and power curve. No party recommended changes to address factors: (6) changes in allowed ROE; and (8) construction delays.

NIPPC did not provide comments on the eight identified risk items. Rather, NIPPC makes two recommendations on the structure of the RFP process: (1) require mandatory Commission acknowledgement of the utilities' shortlists; or (2) require utilities to procure certain resources through RFPs that do not include a utility ownership option and where IPPs will exclusively compete with one another.

B. Discussion of Specific Risks

In Order No. 13-204, we directed the parties to initially address whether each risk factor is related to resource ownership, and provide support for any conclusion reached. If a risk factor is related to ownership, we requested that parties provide recommendations to help the IE's comparative analysis of that risk item for utility benchmark resources and other resource options.

1. Changes in Forced Outage Rates Over Time

a. Description of the Issue

Staff and the utilities generally agree that both utility-owned and PPA resources run the risk of a higher forced outage rate because a resource may become less available than anticipated over time. Staff stresses that this risk factor is tied to resource ownership, because customers bear the risk of a higher outage rate for only utility-owned resources. Pacific Power and PGE point out, however, that customers may also benefit from a lower than expected outage rate.

To estimate forced outage rate assumptions for its benchmark resource, Pacific Power and Idaho Power rely on outage rate data from industry experience, and Pacific Power specifically takes into account original equipment manufacturer (OEM) data for specific types of rotating equipment. PGE explains that it scores benchmark bids by accounting for the actual cost of the long-term service agreement (LTSA) for the term of the agreement and an escalated service agreement cost for the remaining life of the plant. PGE states that these agreements include regular inspections and repair/replacement of major components, which reduce forced outages.

The utilities explain that they evaluate whether a PPA includes an availability guarantee that includes forced outages. The utilities note that the level of protection provided by PPA agreements varies. PGE also notes that liquidated damages are incomplete protection because the utility is ultimately responsible for its physical supply, and if replacement power cannot be bought then reliability may be jeopardized.

b. Parties' Recommendation

Pacific Power, PGE, and Staff all conclude that the current methods of evaluating forced outage rates are appropriate. Pacific Power, PGE, and Staff state that the Commission's previous finding on heat rate degradation applies, because an accurate evaluation is case specific and the risks and benefits should be evaluated based on the individual characteristics of each resource. Pacific Power also recommends that the IE should review and verify that forced outage rate values are consistent with industry experience and OEM values.

Staff states that a change in a benchmark resource's forced outage rate is reflected in the utility's annual power cost. Staff states that the power cost proceedings provide a structured process for interested parties to scrutinize outage events for prudency before any cost recovery is authorized by the Commission. Idaho Power makes similar points, and further states that the cost impact resulting from increased forced outages at a utility resource would be minimal and would not result in a material difference in bid pricing even if the IE were to assume increased outages. For these reasons, Idaho Power recommends that the comparative analysis should focus only on ensuring that bids include reasonable outage rates.

Staff notes that a PPA may include a range of clauses to address plant availability. Staff recommends the IE conduct an assessment of PPAs to determine whether the contract addresses plant availability during the length of the PPA. In reply, PGE states that it has no objections to Staff's recommendation.

c. Commission Resolution

We generally agree with the utilities and Staff that no significant changes are needed to account for forced outage rates. It appears that both benchmark bids and PPA offers include availability or outage estimates. It also appears that the IE checks these values when they are included.

Nonetheless, because utility customers bear the risk of a benchmark resource that becomes less available than anticipated over time, we are adding forced outage rates to a list of factors in Guideline 10(d) that the IE must explicitly examine. The IE must review and verify that forced outage rate values for benchmark resources are consistent with industry experience and OEM values. In addition, the IE must check for reasonableness any availability provisions in a short-listed PPA. The IE may include its analysis of these factors in its closing report.

2. *End Effect*

a. Description of the Issue

Staff and the utilities contend that, unlike PPAs, utility ownership bids provide end effects, or terminal value, which they describe as the salvage value of the equipment, the inherent value of a wind or hydro site, or decommissioning costs. Pacific Power and Idaho Power explain that, when a resource has benefits beyond the useful life assumed in the original benchmark proposal, a utility has the obligation to extend the benefits to customers, while an IPP with a PPA does not. For example, a utility may continue to operate the resource at cost, whereas the IPP will likely opt to sell the project output at market. The utilities and Staff note that under a PPA, customers incur no additional costs, nor do they receive additional benefits once the contract ends.

Pacific Power states that it includes a terminal value as part of its shortlist development. Pacific Power considers the terminal value of an asset, utility or IPP-owned, to be quantifiable at the time of the resource proposal, and whether or not to include this value is made on a case-by-case basis.

PGE points out, that current, competitive bidding guidelines capture decommissioning costs and salvage values of utility-ownership bids, but do not capture the option value (benefits) of repowering the site or extending the life of the plant through upgrades, component replacement, and capital improvements.

b. Parties' Recommendations

The utilities recommend that the Commission direct the IE to consider end effect. The utilities agree that utility-owned resources provide a terminal value that a PPA does not, and that the IE should account for this value differential.

Staff agrees with the utilities in principle that the terminal value of a benchmark resource should be taken into consideration by the IE in bid evaluation, though Staff notes that the end-of-life effect may be negative or positive. Ultimately, Staff suggests that PPA bidders be invited, on a case-by-case basis, to offer an option to renew their PPA at the end of the initial term. Staff notes that ratepayers may benefit from extending PPAs with specific valuable attributes, for example a valuable wind site. Staff explains that an option to renew equalizes the benefits from a utility-owned resource and PPA resource, and allows the IE to consider bids with and without end effect. In reply comments, PGE states that it has no objection to inviting PPA bidders to offer an option to renew, and also recommends the IE consider the economic value of the option to repower a utility site.

c. Commission Resolution

We find that end effect is a risk factor that is tied to resource ownership, and acknowledge that utilities generally include terminal value in bids for a benchmark resource. To ensure that all bids are fairly evaluated, we agree with Staff that IPP bidders should be allowed to include a terminal value in their bids. We note that this risk item has most commonly arisen in the context of wind RFPs. Thus, we direct the utilities to allow IPPs to submit bids both ways, without and with an option to renew, and we have included this requirement as a new subsection, Guideline 10(f), shown below. We have also included end effect in the list of factors in Guideline 10(d) that we are directing the IE to check for reasonableness, to ensure that short-listed bids, whether a benchmark resource or PPA, contain reasonable terms.

We decline to adopt PGE's recommendation regarding a utility including the option to repower a site. We are focused on increasing the IE's analysis to address the bias that favors benchmark resources in the RFP process, and PGE's proposal would not further our goals.

3. Environmental Regulatory Risks

a. Description of the Issue

Staff states that this risk is tied to resource ownership because, with a benchmark resource, customers may pay for the costs associated with changes in environmental regulations. The utilities and Staff add that a PPA may provide less customer risk if the IPP contractually agrees to assume the environmental regulatory risk. However, the utilities note that IPPs generally will not accept this risk and will use "change in law" provisions to assign risks to the utility or excuse their performance. Idaho Power's past experience has shown that, even if the IPP does accept the full risk for future compliance costs, IPP developers will simply abandon the project if the forward-looking economics of the project do not show a profit. PGE and Pacific Power agree that sufficiently large and unforeseen costs may lead to contract renegotiation or default, which would cause the utility to purchase replacement power or step in to ensure compliance.

b. Parties' Recommendation

Pacific Power reasons that the current process for reviewing environmental regulatory risk adequately accounts for the associated comparative risks between utility and third-party owned resources because the IE evaluates compliance costs for future carbon dioxide (CO_2) emissions that Pacific Power includes in its benchmark proposal. Similarly, Idaho Power states that its benchmark bid price includes assumptions regarding future regulatory compliance, and Idaho Power assumes that an IPP bid would also include compliance costs.

Idaho Power and Staff both recommend that the IE's comparative analysis should make sure that the bids reasonably account for *anticipated* future environmental regulations. Staff adds that the IE should review and evaluate any "change in law" clause associated with the IPP resource.

Regarding *unanticipated* future regulations, PGE and Idaho Power state that accounting for the impact of unknown future regulations in the comparative analysis would be difficult, if not impossible.

c. *Commission Resolution*

Similar to our finding on forced outage rates above, we find that this factor is tied to resource ownership insofar as utilities' benchmark bids may not capture all the costs of environmental compliance that may be passed on to customers in rates. Although it appears that the IE is already checking that benchmark bids include reasonable values for CO_2 emissions compliance as emission costs have been included in the price score criteria of recent RFPs, we explicitly include consideration of environmental emissions in the list of factors in Guideline 10(d) to ensure these costs are appropriately analyzed.

4. Increases in Fixed O&M Costs Over Time

a. *Description of Issue*

The parties dispute whether increases in fixed O&M costs over time are linked to utility ownership. Staff states that utility customers pay for prudently incurred fixed O&M costs associated with a benchmark resource, regardless of the estimate in the bid, whereas a PPA contains an expected level of fixed O&M costs over the contract period. PGE disagrees, stating that long-term service agreements cover a large part of utility-owned plant fixed O&M costs and therefore reduce the variability of realized costs. In addition, PGE and Pacific Power both note that regulatory reviews allow customers to benefit from lower than projected benchmark O&M costs. Idaho Power adds that, if the O&M costs unexpectedly increase for a PPA, the IPP would likely ask for contract renegotiation or seek other relief.

Pacific Power adds that currently, for its benchmark resource, it develops cost estimates using information from its existing generation fleet as well as from contract-based costs provided by the manufacturer for planned maintenance services of major equipment.

b. *Parties' Recommendation*

PGE states that, similar to its discussion of forced outage rates, this risk factor is not material and is already adequately considered in the scoring criteria. Idaho Power agrees, stating that the cost impacts of changes in fixed O&M costs over the life of a resource are not significant enough to warrant additional comparative analysis by the IE. Like forced outage rates, the IE's comparative analysis should focus only on ensuring that the O&M costs included in bids are reasonable.

Staff recommends that the IE compare the fixed O&M costs included in the PPAs and the utility benchmark to the escalation factor for O&M costs recently used in utility IRPs and general rate cases. In reply comments, PGE states that in its most recent RFP (docket UM 1535), the IE compared the fixed O&M costs included in the IPP and benchmark bids to the escalation factor for O&M costs used in PGE's most recent IRP (docket LC 48). Thus, PGE recommends no changes be made.

c. Commission Resolution

Similar to forced outage rates and environmental regulatory risk, as discussed above, it appears that the IE already reviews the O&M values for reasonableness. We agree with Staff that the IE should continue to review O&M values in the future, and to the extent necessary, compare the utility benchmark value with comparable values from IRPs or rate cases. To ensure this issue is examined, we are including increases in fixed O&M costs over time in the list of factors in Guideline 10(d) for the IE's analysis.

5. Capital Additions over the Resource Life

a. Description of the Issue

Staff and the utilities agree that the risk of capital additions is tied to utility ownership because, unlike PPA bids, customers will generally pay for prudently incurred capital additions to a benchmark resource regardless of what the bid states. The parties note, however, that this risk is generally mitigated. Pacific Power and Idaho Power explain that their benchmark resource proposals include reasonably expected capital additions that will occur over the course of the resource life. Pacific Power uses a fixed price contract that covers planned capital additions that are part of a long-term maintenance program for major equipment, as well as a contingency to account for unforeseen project costs. Idaho Power assumes that IPPs also include reasonably anticipated capital additions.

PGE adds that customers are more likely to benefit from post-construction capital additions, because post-construction capital additions often involve a change in the use of the plant, or an improvement in plant efficiency. These costs would only be approved and undertaken if they provided a net benefit to customers. Thus, PGE reasons that these costs should have no effect on the original resource selection.

b. Parties' Recommendation

Staff and PGE recommend that no further action is needed to address this risk factor. They note that the Commission addressed the risk of cost over-runs in its previous order in this proceeding, and state that those findings also apply to this capital additions risk factor. There, the Commission found that "utilities can minimize any costs over-run risk by seeking fixed price guarantees or contingency reserves, and generally adjust self-builds to account for possible work orders and other risks."[7] The Commission directed the IE "to provide a more comprehensive accounting of the risks and benefits to ratepayers for construction cost over-runs and under-runs."

[7] Order No. 13-204 at 9.

Idaho Power relies on the experience of the IE to ensure that all costs and cost components are included in both utility benchmark resource and IPP bids, reasoning that this issue is already accounted for in the bidding process.

Pacific Power states that the Commission could instruct the IE to review a utility's long-term maintenance programs and assess whether or not the utility has included reasonably expected future capital additions. Unforeseeable future capital investments should not be assumed. In its reply comments, PGE has no objection to Pacific Power's recommendation.

c. Commission Resolution

We recognize the similarity of capital additions to construction cost over-runs considered in our previous order, and we agree that the same rationale applies. To the extent practicable, utilities should continue to reduce this risk factor by accounting for future resource additions with fixed price proposals and a contingency to cover additional costs. It appears the utilities may already include expected future capital additions in their benchmark bid and take these precautions. However, we include this factor in Guideline 10(d) to ensure the IE continues to examine benchmark bids for reasonably expected capital additions.

6. Changes in Allowed Return on Equity over the Resource Life

a. Description of the Issue

The parties describe this issue as one specific to utility-owned resources that examines whether customers are at risk from increases in plant-related revenue requirements resulting from changes to authorized ROE over time.

Pacific Power explains that it currently applies its allowed ROE as a component of its weighted average cost of capital for a benchmark resource proposal. For a third-party owned resource, Pacific Power does not evaluate the third party's expectation regarding the return on its investment.

b. Parties' Recommendation

The utilities and Staff do not recommend further action on this risk item. Pacific Power reasons that the Commission's oversight with respect to ROE minimizes the risk to customers of changes. PGE notes that any risk of increases in ROE is balanced by potential decreases in ROE. PGE states that its ROE has consistently decreased since 1990. PGE also adds that the potential risk has not materialized, and points to Staff's analysis showing that historical changes in ROE did not impact the cost to customers of utility-owned resources. Idaho Power makes similar points, stating that it is impossible to accurately predict how a utility's ROE will change over time, difficult to imagine how predicted changes could be applied, and therefore there is no way to compare a future utility ROE to the ROE included in an IPP's bid.

c. *Commission Resolution*

ROE has long been one of the factors identified in our build-versus-buy investigations.[8] In these proceedings, however, the parties have not shown that changes in a utility's ROE materially contribute to the risk of favoring utility-owned resources. We decline to adopt any changes to address this factor.

7. *Output, Heat Rate, and Power Curve at the Start of Resource Life*

a. *Description of the Issue*

This issue addresses the comparison of the resource's actual performance at its in-service date to the performance metrics assumed in the bids. PGE states that this risk is not related to ownership, because both utilities and IPPs follow best practices by testing the performance of a plant at the end of commissioning to verify the contractual guarantees for output (power) and heat rate.

Pacific Power explains that it models performance changes for benchmark resources based on OEM or other proxy performance degradation data. Pacific Power applies the same performance adjustments to PPAs unless the third party provides performance guarantees.

b. *Parties' Recommendation*

Staff states that performance verification protocols should be applied to IPP resources and benchmark resources upon resource completion so there is a baseline to judge the performance of a resource. Staff recommends that remedies be put in place in order to limit negative impacts on ratepayers. Staff also recommends that the IE verify that the RFP includes the same performance measures for a PPA and benchmark in terms of total annual output, average annual output, minimum and maximum net output.

In response to Staff's recommendation, Pacific Power agrees that bids should include the performance parameters listed. However, to the extent Staff intends additional performance verification protocols to apply at the time of resource completion, Pacific Power disagrees. Pacific Power instead recommends that the IE review and validate that long-term performance assumptions are reasonable, and generally Pacific Power finds that current methods properly evaluate performance expectations.

Idaho Power states that actual resource performance will not be known until the in-service date, and therefore cannot be a basis by which the IE can compare an IPP bid to a benchmark resource. Idaho Power concludes that this risk factor should not be included in the IE's comparative analysis. PGE also states that no changes should be made to the

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[8] *See* Order No. 11-001 at 2 (stating that owned resources offer a utility an opportunity to earn a return, while PPAs do not).

IE's comparative analysis, but it does not object to Pacific Power's or Staff's recommendations.

c. Commission Resolution

The parties explain that output, heat rate, and power curve are measured and verified at the time of resource completion. At this time, we will not require utilities to provide damages for underperformance, because we expect utilities to include reasonably accurate output estimates in their benchmark bids. Thus, we direct the IE to review, or continue to review and validate that long-term output and performance assumptions are reasonable, and we are including this factor in the IE's list in Guideline 10(d).

We also note that this requirement may be unnecessary for future wind RFPs, because Order No. 13-204 requires that the capacity factor of short-listed wind projects be subject to expert third-party review.[9]

8. Construction Delays

a. Description of the Issue

Staff and the utilities agree that this issue applies to both PPAs and a utility-owned resource and generally agree that liquidated damages included in contracts mitigate this risk factor. The parties explain that construction of a utility-owned resource often involves an Engineering, Procurement, and Construction (EPC) contract that includes remedies, such as liquidated damages, in the event of a construction delay. Likewise, PPAs generally include similar remedies in the event that the IPP experiences a delay in constructing its project. The utilities explain that the liquidated damages incent contractors to meet the guaranteed deadlines, and are generally calculated to cover the cost of replacement power.

Idaho Power and Staff note that, when a construction delay occurs, customers will not pay the construction costs of either a benchmark or a PPA until each project is actually in service. They explain that, for a benchmark resource, customers will not begin paying the capital costs of the resource until the Commission determines it is used and useful. Similarly, the terms of a PPA will generally protect customers by ensuring that customers are not paying for power that is not being delivered.

Idaho Power and Staff state that, in the event of a construction delay for either type of resource, the utility will need to go to market to purchase replacement power. Market prices may be higher or lower than the costs of a utility-owned resource or the PPA, or higher or lower than the contracted-for liquidated damages. In both cases, the utility and its customers will be taking that risk. Staff concludes that the risk to customers from a benchmark resource is not clearly defined because it could be either a benefit or a cost.

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[9] Order No. 13-204 at 10-11.

b. Parties' Recommendation

Pacific Power, PGE, and Staff recommend that no further action is necessary for this risk item. Pacific Power explains that the current bid evaluation process takes into account the reasonableness of the project schedule and gives credit to third parties who bear the risks associated with construction delays. Pacific Power explains that its current process assumes that both a benchmark resource and PPAs will meet their contractually proposed in-service dates. For PPAs, if the third party will contractually agree to bear the risk of a construction delay, the PPA receives a higher non-price score. For a benchmark resource, the construction schedule is evaluated based on the level of specificity in the schedule.

Idaho Power believes it is better to resolve contract delay issues as part of contract negotiation with an IPP as opposed to making it a key part of the RFP analysis.

c. Commission Resolution

Similar to several of the factors above, construction schedules may already be adequately evaluated in the scoring. However, we see no harm in adding construction schedules to the list of factors that the IE must analyze.

C. NIPPC's Proposals

NIPPC maintains that all the identified risk factors are related to utility resource ownership and that the costs of these risks are eventually borne by ratepayers years later. NIPPC states that it does not believe that additional qualitative adjustments to the IE's analysis will mitigate or eliminate these risks, nor entice IPPs to participate in Oregon utility procurements.

For that reason, NIPPC did not offer comments on the identified risk factors and, instead, suggests two changes to the RFP process: (1) a requirement that utilities submit their shortlist to the Commission for approval; or (2) a requirement that utilities procure certain resources through RFPs that do not include a utility ownership option and where IPPs will exclusively compete with one another.

In response to NIPPC's comments, Staff recommends that the Commission should open another phase of this docket to consider Commission acknowledgement of utilities' shortlist, but that the Commission should deny NIPPC's suggestion for a set aside for IPP-only RFPs. The utilities strongly object to NIPPC's proposals arguing they are outside the scope of this docket, untimely, lack evidentiary support, and would undermine the competitiveness of the current RFP process.

1. Commission Acknowledgement of the Shortlist

NIPPC explains that the Commission's existing guidelines do not require the utility to bring its shortlist of final bidders to the Commission for acknowledgement. NIPPC believes this omits an important opportunity for the IE to demonstrate to the Commission and Staff how short-listed resources compare with the benchmark resource and with one another and whether they are all being evaluated evenly. NIPPC maintains that by presenting the shortlist to the Commission, the utilities would provide transparency into the process without unduly constraining utility management. Acknowledgement would also provide the Commission with important information to assess that the RFP will, in fact, deliver least cost, least risk resources to Oregon customers. NIPPC's cites PGE's recent thermal RFP as a negative example that could have been improved with shortlist acknowledgement, and Pacific Power's previous RFP as a positive example where shortlist acknowledgement provided transparency.

a. Staff's and Utilities' Response

Although Staff notes that NIPPC's proposal to require mandatory acknowledgement of the shortlist was not identified as an issue in this docket, Staff believes that NIPPC has suggested a reasonable change. Staff notes that it has in the past strongly supported acknowledgement of the shortlist of bidders, but that Guideline 13, as approved in Order No. 06-446, does not make acknowledgement mandatory. Staff agrees with NIPCC that, had PGE sought acknowledgement of its final shortlist for its 2012 RFP, parties could have provided input and additional process would have increased the level of satisfaction with PGE's RFP process.[10] Because this issue was not identified as one for comment in this proceeding, however, Staff recommends that we set an additional procedural schedule for further comment.

Idaho Power disputes the relevance of the PGE RFP that NIPPC references. Idaho Power states that the Commission reviewed PGE's process and confirmed the IE's conclusion that the RFP was conducted in a fair and unbiased manner, and identified bids with the most value for PGE customers. Because NIPPC has not identified any instance where Commission acknowledgement would have remedied a deficiency in the RFP process, Idaho Power asserts that the Commission should reject NIPPC's recommendation.

Pacific Power contends there is no need to change the Commission's determination in Order No. 06-446 that acknowledgment of a shortlist is discretionary and not mandatory. Pacific Power maintains that utilities need the flexibility not to seek acknowledgement of the shortlist when it is in customers' best interests, for example due to timing. In addition, Pacific Power emphasizes the limited effect of Commission acknowledgment. As clarified in Order No. 06-446, acknowledgement of the shortlist only means that the Commission agrees that the shortlist seems reasonable, and does not provide a guarantee of favorable ratemaking treatment.[11]

PGE contends that this issue is outside the scope of this proceeding, but does note that the process, scope, and timing of any acknowledgement of the shortlist would require careful

[10] Staff Reply Comments at 7 (citing Docket No. DR 46, *In the Matter of Troutdale Energy Center, LLC*, and Docket No. UM 1535, *Request for Investigation of Grays Harbor Energy*).
[11] Order No. 06-446 at 14-15.

consideration because competitive bids are limited in duration. PGE states its customers should not lose the lowest risk, least cost bids due to a protracted acknowledgement process. PGE recommends that, if the Commission would like to address NIPPC's new issues, it should either hold a prehearing conference to establish the scope and schedule of any additional proceeding, or should request an expedited comment schedule to allow all parties to fully comment on these two issues.

b. Commission Resolution

We find that mandatory shortlist acknowledgement is a reasonable change that furthers the goal of this docket, and reverse our conclusion in Order No. 06-446 that acknowledgement should be discretionary. We believe that requiring mandatory acknowledgment will provide incremental improvements to the RFP process without causing undue burdens to the utility's ability to conduct negotiations with top bidders.

First, requiring utilities to file a shortlist acknowledgment application will promote transparency in the utility procurement process by providing an established, upfront opportunity for parties and bidders to voice concerns with the bidding process. This will allow the Commission to timely review the IE's closing report and address any issues the IE raises with the bidding process or the shortlist. We expect this additional oversight of the shortlist will address the impact of the bias throughout the RFP process, ultimately benefiting ratepayers by helping ensure the utility selects the most competitive bids.

Second, contrary to the utilities' concerns over shortlist acknowledgement causing delay, we believe that mandatory acknowledgement will provide a more streamlined and defined process. The certainty of mandatory acknowledgement should reduce instances when the Commission requires acknowledgement on a case-by-case basis,[12] or holds additional proceedings to address concerns after the RFP process has concluded.[13]

To ensure acknowledgement does not cause delays, we modify Guideline 13 to also include an expedited schedule for our review. That schedule will provide that, once the shortlist acknowledgment application is filed, the Commission will consider the matter at a public meeting within 60 days of receiving the utility's application. By adopting this deadline the utility can plan ahead and negotiate bids that extend to cover this time.

Further, if even an expedited acknowledgment will interfere with negotiation deadlines that cannot be avoided, we will allow a utility to seek waiver of this requirement for good cause shown. When filing a waiver, the utility will be required to show that the time

[12] *See In the Matter of PacifiCorp, dba Pacific Power, Requests Approval to Resume 2008 Request for Proposal,* Docket No. UM 1360, Order No. 09-491 at 2 (Dec 14, 2009) (conditioning resumption of RFP on shortlist acknowledgement).
[13] *See generally In the Matter of Portland General Electric Co, Request for Proposals for Capacity Resources,* Docket No. UM 1535; and *In the Matter of Troutdale Energy Center, LLC, Petition for Declaratory Ruling,* Docket No. DR 46 (two related requests for investigation into PGE's 2012 RFP).

required for a shortlist acknowledgement will preclude the ability to successfully complete negotiations with a top bidder, thereby causing harm to its ratepayers.

We acknowledge the concerns raised that this issue was not one of the eight risk factors identified for this phase, and generally would not address a new issue without a modification to the scope of these proceedings. Nonetheless, we take this unusual action to address and adopt NIPPC's recommendation for three reasons. First, we want to complete this docket and decline to extend it for further investigation. Second, the decision of whether to require acknowledgment is a policy determination that lies within the Commission's discretion, and although not identified for discussion, all parties had the opportunity to address NIPPC's proposal in reply comments. Third, and most importantly, we believe we have addressed the utilities' concerns by adopting an expedited schedule for acknowledgment and allowing a waiver of the requirement for good cause shown.

Finally, we find that housekeeping revisions are needed to Guideline 11 to clarify that the utility, and not the IE, is responsible for sharing the IE's closing report with qualified persons. Currently, Guideline 11 directs the IE to prepare a closing report and to share its evaluation results with qualified persons. We will replace this language to clarify that the utility must include the IE's closing report in its shortlist acknowledgment application. This will ensure that all qualified persons under the protective order receive the report at the same time, and that the Commission will be able to complete a prompt and thorough review of the application with all documents in hand. Guideline 11 is modified as shown below.[14]

We also memorialize a current informal process. Since 2010, the Commission has allowed the IE as a "qualified person" under its protective order. We have also required the utilities to routinely include a clause in their contracts with the IE to ensure the IE is under the Commission's jurisdiction for possible enforcement of a violation of the protective order by the IE. This practice will continue. By designating the IE as a qualified person, parties to the proceedings may send their own confidential material to the IE for the IE's review and consideration.

2. Set Aside for an IPP-only RFP

In the alternative to shortlist acknowledgment, NIPPC requests modification to the RFP guidelines that would require utilities to set aside a portion of any RFP for IPP resources. NIPPC asserts that its proposal is consistent with IRP guideline 13, which requires utilities to assess the advantages of purchasing power from another party.[15] Specifically,

[14] This requirement replaces the procedures outlined in the March 4, 2010 memo from Staff. That memo stated that the utility would use its best efforts to quickly send the IE's report to qualified persons, and then redact the report within a reasonable period of time for service on other parties to the RFP proceeding. Our revision provides that the utility will need to simultaneously file and serve both a confidential and redacted version of its shortlist application including the IE's closing report.

[15] *In the Matter of an Investigation into Integrated Resource Planning,* Docket No. UM 1056, Order No. 07-002 (Jan 8, 2007).

NIPPC suggests the Commission require the utilities to clearly identify the actual amount of nameplate megawatts that the utilities plan to secure through purchases of power generated by unit contingent resources that they do not intend to build or subsequently acquire. NIPPC explains that this would provide a pre-determined set aside that would allow IPPs to compete amongst one another in a RFP.

a. Staff's and Utilities' Response

Staff and the utilities object to NIPPC's proposal. Staff does not believe that this recommendation could be implemented without a significant investigation into the impacts of such a drastic policy change on rates and analysis of how resources acquired under such a policy would fit in the utilities' IRPs.

Pacific Power agrees that the Commission's IRP guidelines are not part of this docket. Pacific Power adds that NIPPC's proposal is impractical because Pacific Power's current IRP process allows both front office transactions and resources to be selected as part of the preferred portfolio.

Idaho Power states that NIPPC's proposed set aside amounts to an unreasonable subsidy for IPPs and frustrates the basic purpose of competitive bidding – identifying and procuring the least cost and least risk resources to serve customers. If benchmark resources are categorically excluded, it will make the process non-competitive. Idaho Power stresses that all resources must compete against one another to provide confidence that the acquired resource is least cost and least risk.

b. Commission Resolution

We decline to address this issue for two reasons. First, this proposal was presented as an alternative to NIPPC's recommendation that we require shortlist acknowledgement, which we adopted. Second, and more importantly, NIPPC's proposal is contrary to the goal underlying the IRP process that utilities obtain resources that are least risk and cost to ratepayers. Absent clear legislative direction, we are unwilling to consider any mechanism that would require a utility to procure certain types of resources regardless of the impact on customer rates.

IV. CONCLUSION

Considering our findings above, as well as our findings in Orders Nos. 13-204 and 11-340, we modify the RFP Guidelines from Order No. 06-446 as follows:

Guideline 10 is modified to read:

* * * * *

d. *If the RFP allows affiliate bidding or includes ownership options, the IE will independently score the utility's Benchmark Resource (if any) and all or a sample of the bids to determine whether the selection for the initial and final shortlists are reasonable. In addition, the IE will evaluate the unique risks and advantages associated with the Benchmark Resource (if used), including ~~the regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected for the RFP.~~ an evaluation of the following issues: construction cost over-runs (considering contractual guarantees, cost and prudence of guarantees, remaining exposure to ratepayers for cost over-runs, and potential benefits of cost under-runs); reasonableness of forced outage rates; end effect values; environmental emissions costs; reasonableness of operation and maintenance costs; adequacy of capital additions costs; reasonableness of performance assumptions for output, heat rate, and power curve; and specificity of construction schedules or risk of construction delays. The IE may also consider these issues as applicable to third party bids.*

* * * * *

f. *Wind RFPs: Utilities are to allow independent power producers to submit bids with and without an option to renew. Utilities are to use qualified and independent third-party experts to review the expected wind capacity factor for all projects on the shortlist.*

Guideline 11 is modified to read:

11. IE Closing Report: *The IE will prepare a Closing Report for the Commission after the utility has selected the final shortlist. ~~In addition, the IE will make any detailed bid scoring and evaluation results available to the utility, Commission staff, and non-bidding parties in the RFP docket, subject to the terms of a protective order.~~ The utility shall include the IE's Closing Report in the shortlist acknowledgement application that is filed with the Commission and served on the parties.*

Guideline 13 is modified to read:

13. RFP Acknowledgment: *Except upon a showing of good cause, the utility ~~may~~ must request that the Commission acknowledge the utility's selection of the final shortlist of RFP resources. The IE will participate in the RFP acknowledgment proceeding. Acknowledgment has the same meaning as assigned to that term in Commission Order No. 89-507. RFP acknowledgment will have the same legal force and effect as IRP* *acknowledgment in any future cost recovery proceeding. The utility's request should discuss the consistency of the final shortlist with the company's acknowledged IRP Action Plan. The Commission will consider the request to acknowledge at a public meeting within 60 days of receiving the utility's application.*

Commission Staff will make a recommendation about whether the Commission should require IE involvement through final resource selection at the time of acknowledgement of the utility's final shortlist of resources. Other parties, including bidders, may request expanded IE involvement at that time.

A copy of the complete guidelines, as revised by the decisions in Orders No. 11-340, 12-007, 13-204 and this order, is attached as Appendix A for the parties' convenience.

V. ORDER

IT IS ORDERED that Competitive Bidding Guidelines 10, 11, and 13 are modified, as discussed above, and this docket is closed.

Made, entered, and effective APR 30 2014.

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

UM 1182
Competitive Bidding Guidelines

1. RFP Requirement: A utility must issue an RFP for all Major Resource acquisitions identified in its last acknowledged IRP. Major Resources are resources with durations greater than 5 years and quantities greater than 100 MW. If multiple small generating resources total more than 100 MW and meet the following criteria, then there is a rebuttable presumption that the multiple small resources are a single Major Resource and the competitive bidding guidelines apply:

a. The small resources are located on one parcel of land or on two or more adjacent parcels of land, or the generation equipment of any small resource is within five miles of the generation equipment of any other small resource; and

b. Construction of the resources is performed by the same contractor, or under the same contract, or under multiple contracts entered into within two years of each other.

A single area of land is considered one parcel even if there is an intervening public or railroad right of way.

The utility bears the burden of rebutting this presumption. If multiple small resources meet these criteria, but the utility believes that other factors show that each resource is separate and distinct, then the utility may request that the Commission find that the resources do not qualify as a single Major Resource. If the utility proceeds without making this request and without following the competitive bidding guidelines, then the utility may attempt to rebut the presumption that it should have followed the guidelines when the utility seeks recovery of the costs of the resource in rates.

2. Exceptions to RFP Requirement: A utility is not required to issue an RFP under the following circumstances:

a. Acquisition of a Major Resource in an emergency or where there is a time-limited resource opportunity of unique value to customers.

b. Acknowledged IRP provides for an alternative acquisition method for a Major Resource.

c. Commission waiver on a case-by-case basis.

Within 30 days of a Major Resource acquisition under Subsection (a) above, the utility must file a report with the Commission explaining how the requisite conditions have been met for acting outside of the RFP requirement. The report must be served on all the parties and interested persons in the utility's most recent rate case, RFP and IRP dockets.

When requesting a waiver under Subsection (c) above, the utility must file its request with the Commission and serve the request on all parties and interested persons in the utility's most recent general rate case, RFP and IRP dockets. The Commission will issue an order addressing the waiver request within 120 days, taking such oral and written comments as it finds appropriate under the circumstances.

3. **Affiliate Bidding:** A utility may allow its affiliates to submit RFP bids. If affiliates are allowed to bid, the utility must blind all RFP bids and treat affiliate bids the same as all other bids.

4. **Utility Ownership Options:** A utility may use a self-build option in an RFP to provide a potential cost-based alternative for customers. A site-specific, self-build option proposed in this way is known as a Benchmark Resource. A utility may also consider ownership transfers within an RFP solicitation.

5. **Independent Evaluator (IE):** An IE must be used in each RFP to help ensure that all offers are treated fairly. Commission Staff, with input from the utility and interested, non-bidding parties, will recommend an IE to the Commission, which will then select or approve an IE for the RFP. The IE must be independent of the utility and likely, potential bidders and also be experienced and competent to perform all IE functions identified in these Guidelines. The IE will contract with and be paid by the utility. The IE should confer with Commission Staff as needed on the IE's duties under these Guidelines. The utility may request recovery of its payments to the IE in customer rates.

6. **RFP Design:** The utility will prepare a draft RFP and provide it 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 below. 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 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.

7. **RFP Approval:** The Commission will solicit public comment on the utility's final draft RFP, including the proposed minimum bidder requirements and bid scoring and evaluation criteria. Public comment and Commission review should focus on: (1) the alignment of the utility's RFP with its acknowledged IRP; (2) whether the RFP satisfies the Commission's competitive bidding guidelines; and (3) the overall fairness of the utility's proposed bidding process. After reviewing the RFP and the public comments, the Commission may approve the RFP with any conditions and modifications deemed necessary. The Commission may consider the impact of multi-state regulation, including

requirements imposed by other states for the RFP process. The Commission will target a decision within 60 days after the filing of the final draft RFP, unless the utility requests a longer review period when it submits the final draft RFP for approval.

8. Benchmark Resource Score: The utility must submit a detailed score for any Benchmark Resource, with supporting cost information, to the Commission and IE prior to the opening of bidding. The score should be assigned to the Benchmark Resource using the same bid scoring and evaluation criteria that will be used to score market bids. Information provided to the Commission and IE must include any transmission arrangements and all other information necessary to score the Benchmark Resource. If, during the course of the RFP process, the utility, with input from the IE, determines that bidder updates are appropriate, the utility may also update the costs and score for the Benchmark Resource. The IE will review the reasonableness of the score(s) for the Benchmark Resource. The information provided to the Commission and IE will be sealed and held until the bidding in the RFP has concluded.

9. Bid Scoring and Evaluation Criteria:

a. Selection of an initial shortlist of bids should be based on price and non-price factors, and provide resource diversity (e.g., with respect to fuel type and resource duration). The utility should use the initial prices submitted by the bidders to determine each bid's price score. The price 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.

b. Selection of the final shortlist of bids should be based, in part, on the results of modeling the effect of candidate resources on overall system costs and risks. The portfolio modeling and decision criteria used to select the final shortlist of bids must be consistent with the modeling and decision criteria used to develop the utility's acknowledged IRP Action Plan. The IE must have full access to the utility's production cost and risk models.

c. Consideration of ratings agency debt imputation should be reserved for the selection of the final bids from the initial shortlist of bids. The Commission may require the utility to obtain an advisory opinion from a ratings agency to substantiate the utility's analysis and final decision.

10. Utility and IE Roles in RFP Process:

a. The utility will conduct the RFP process, score the bids, select the initial and final shortlists, and undertake negotiations with bidders.

b. The IE will oversee the RFP process to ensure that it is conducted fairly and properly.

c. If the RFP does not allow affiliate bidding and does not include ownership options (i.e., the utility is not including a Benchmark Resource or considering ownership transfers), the IE will check whether the utility's scoring of the bids and selection of the shortlists are reasonable.

d. If the RFP allows affiliate bidding or includes ownership options, the IE will independently score the utility's Benchmark Resource (if any) and all or a sample of the bids to determine whether the selection for the initial and final shortlists are reasonable. In addition, the IE will evaluate the unique risks and advantages associated with the Benchmark Resource (if used), including an evaluation of the following issues: construction cost over-runs (considering contractual guarantees, cost and prudence of guarantees, remaining exposure to ratepayers for cost over-runs, and potential benefits of cost under-runs); reasonableness of forced outage rates; end effect values; environmental emissions costs; reasonableness of operation and maintenance costs; adequacy of capital additions costs; reasonableness of performance assumptions for output, heat rate, and power curve; and specificity of construction schedules or risk of construction delays. The IE may also consider these issues as applicable to third party bids.

e. Once the competing bids and Benchmark Resource (if used) have been scored and evaluated by the utility and the IE, the two should compare results. The utility and IE should attempt to reconcile and resolve any scoring differences. If the two are unable to agree, the IE should explain the differences in its Closing Report.

f. Wind RFPs: Utilities are to allow independent power producers to submit bids with and without an option to renew. Utilities are to use qualified and independent third-party experts to review the expected wind capacity factor for all projects on the shortlist.

11. IE Closing Report: The IE will prepare a Closing Report for the Commission after the utility has selected the final shortlist. The utility shall include the IE's Closing Report in the shortlist acknowledgement application that is filed with the Commission and served on the parties.

12. Confidential Treatment of Bid and Score Information: Bidding information, including the utility's cost support for any Benchmark Resource, as well as detailed bid scoring and evaluation results will be made available to the utility, Commission Staff and non-bidding parties under protective orders that limit use of the information to RFP approval and acknowledgment and to cost recovery proceedings.

13. RFP Acknowledgement: Except upon a showing of good cause, the utility must request that the Commission acknowledge the utility's selection of the final shortlist of RFP resources. The IE will participate in the RFP acknowledgment proceeding. Acknowledgment has the same meaning as assigned to that term in Commission Order No. 89-507. RFP acknowledgment will have the same legal force and effect as IRP acknowledgment in any future cost recovery proceeding. The utility's request should discuss the consistency of the final shortlist with the company's acknowledged IRP Action Plan. The Commission will consider the request to acknowledge at a public meeting within 60 days of receiving the utility's application.

Commission Staff will make a recommendation about whether the Commission should require IE involvement through final resource selection at the time of acknowledgement of the utility's final shortlist of resources. Other parties, including bidders, may request expanded IE involvement at that time.