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June 19, 2009

Lisa Hardie
Administrative Law Judge
Public Utility Commission of Oregon
550 Capitol St NE – Suite 215
PO Box 2148
Salem OR 97308-2148

Re: UM 1429 – OIE Comments on 2009R Final Draft RFP (Boston Pacific Company)

Dear Judge Hardie:

Enclosed with this letter is a document entitled "The Oregon Independent Evaluator's Assessment of PacifiCorp's 2009R Renewables RFP Design" that staff is submitting in PUC Docket UM 1429 on behalf of one of the Oregon Independent Evaluators, Boston Pacific Company.

The attached document is a public document that contains no confidential information. Please note that I am serving this document on the other UM 1429 parties via email only.

Sincerely,

Michael T. Weirich
Assistant Attorney General
Regulated Utility & Business Section

MTW:nal/#1468513
Enclosure
cc: All parties by email only w/enc.

CERTIFICATE OF SERVICE

I certify that on June 19, 2009 I served the foregoing OIE Report upon the parties in this proceeding by electronic mail and by sending a true, exact and full copy by regular mail, postage prepaid, or by hand-delivery/shuttle, to the parties accepting paper service.

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THE OREGON INDEPENDENT EVALUATOR'S ASSESSMENT OF PACIFICORP'S 2009R RENEWABLES RFP DESIGN

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June 19, 2009

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I. INTRODUCTION AND SUMMARY

A. INTRODUCTION

Boston Pacific Company, Inc. was chosen by the Public Utility Commission of Oregon (the Commission) to serve as the Independent Evaluator (IE) for PacifiCorp's 2009R Renewables RFP (2009R RFP or the RFP). We have previously provided comments in this docket on the Company's Initial Draft of the 2009R RFP.[1] This report represents Boston Pacific's analysis of the Final Draft of the 2009R RFP. The purpose of this report is to make a recommendation concerning approval of the 2009R RFP.

B. SUMMARY

Boston Pacific, as the Oregon IE, recommends that the Commission approve the RFP subject to conditions detailed below. Our recommendation is based upon the following points:

(i) The RFP is based on a tested design that attracted a large number of high quality bids. Specifically, the 2009R RFP is based, with very few changes, on the Company's 2008R-1 Renewables RFP. The 2008R-1 RFP requested and received a large number of quality bids for renewable resources this past February. A final shortlist of selected bids from that RFP recently received Commission acknowledgement.

(ii) The RFP design is fair and transparent. The RFP features clear product definitions, requests bids from a wide variety of renewable resources, and allows bidders to propose multiple transaction types. Because it is a renewables-only RFP, bids will have similar characteristics, leading towards a more transparent "price only" evaluation.

[1] See Attachment One. This Attachment also contains the Company's responses, which addressed some of the questions which we raised in our comments.

(iii) The RFP reasonably attempts to measure and allocate risk. The RFP uses a “risk adjustment” methodology, previously used in the Company’s 2008 All Source RFP and approved for use in the 2008R-1 RFP, to attempt to account for the inherent risk in the Company benchmark bid. Because the Company benchmark bid is only an estimate, and not a fixed bid such as bidders will provide, there is a danger that the project could suffer from cost increases. The RFP also accounts for risk more fully by using the Company’s Planning and Risk (PaR) model, which tests the benefits of renewable generation against changes in load, wholesale market prices, gas prices, hydro generation and thermal outages.

(iv) The RFP does not appear to contain any changed provisions or requirements which would keep the process from achieving a positive result. Most bidding qualification requirements remain unchanged from the 2008R-1 RFP and the methodology for determining credit requirements and providing credit is similar as well. One change from the 2008R-1 RFP is that the eligibility criteria in the draft Power Purchase Agreement (PPA) of which banks can provide a Letter of Credit (LOC) has been made slightly more restrictive. We do not think this change will cause major harm to the process, but are interested to hear any comments on the matter from bidders.

(v) The RFP aligns with Commission Guidelines. The RFP fills a need identified in the Company’s Integrated Resource Planning (IRP) process. The RFP also aligns with the IRP process by (a) using inputs from the IRP process in the initial and final shortlist models and (b) using a Company IRP model (the PaR model) to value the benefits of renewable generation. The RFP provides draft agreements and defers the consideration of debt equivalence until after the final shortlist evaluation. To be fully compliant with all guidelines the Company will have to file its benchmark bids and scores with the IE prior to opening of bids.

We propose some conditions for approval, which address a single concern regarding overlap of the 2009R RFP with the 2008R-1 RFP.

(i) We recommend that the Commission condition approval of this RFP on the Company's pledge to work in good faith toward a conclusion of negotiations with shortlisted bidders in the 2008R-1 RFP within three to six months from issuance of this RFP (assuming an early July issuance) as promised by the Company.

(ii) The Commission should further require notification and justification from the Company as soon as the Company has any indications that (a) it will not make this negotiating deadline or (b) that it intends to drop from consideration all bids in the 2008R-1 final shortlist.

(iii) The Commission should also make clear to the Company that, should it drop all 2008R-1 shortlisted bids in favor of a Company benchmark, it will face substantial public skepticism and must be ready to demonstrate that the Company benchmark was a clearly superior choice to those bids. To further address overlap, the Company should encourage shortlisted bidders in the 2008R-1 RFP to place bids in this RFP so that their offers are not lost if negotiations fall through.

II. DESIGN OF THE 2009R RFP

A. PROCESS BACKGROUND

This RFP is based on PacifiCorp's recent 2008R-1 Renewables RFP. More specifically, the 2009R RFP uses almost the exact same RFP document, attachments and appendices as the 2008R-1 RFP.

Boston Pacific served as the Commission's Independent Evaluator (IE) for the 2008R-1 RFP. The drafting and comment process for that RFP was extremely thorough due to the facts that PacifiCorp was proposing a new bid evaluation method (the Alternative Cost of Compliance (ACC) method) and the Company wished to use the RFP design in future procurements.

During the design and comment process Boston Pacific issued several sets of comments on the draft RFP.[2] We described what we looked for in an RFP, pointed out positive features, and recommended changes to areas which we believed would enhance competition and generate a better result for ratepayers. Eventually we recommended approval of the RFP.

The 2008R-1 RFP was issued on October 6, 2008 and re-issued (in order to comply with Utah laws) on January 26, 2009. The work spent on the design and drafting of the RFP was validated by an excellent response from bidders. Eventually, a final shortlist of bids was chosen and the shortlist was acknowledged by the Commission on June 16, 2009.

Because of the positive response to the 2008R-1 RFP and the close relationship between the 2008R-1 and this current 2009R RFP, we now know that this basic RFP design has succeeded in attracting a good number of bidders and identifying those bids which provide the most net benefit to ratepayers.

For the purposes of this report, the linkage between the two RFPs means that many of our comments which were made about the 2008R-1 RFP may be applied to this RFP. Therefore our comments here are brief and focus mainly on changes between the two RFPs. In the following sections we summarize what we look for in an RFP and some of the positive features of the 2009R RFP. We conclude with more detailed comments regarding issues not resolved from our initial comments.

[2] See Attachment Two.

B. RFP DESIGN

What we look for in an RFP

When appraising the design of any competitive procurement process Boston Pacific begins with the goal of the procurement. The goal is to get the best deal possible for ratepayers in terms of price, risk, reliability and environmental performance given market and regulatory conditions. To know if a process will satisfy this goal we look to see if the RFP is (a) fair and transparent, (b) properly measures and assigns risk, (c) will likely lead to a positive result, and (d) is in compliance with regulatory rules and guidelines.

Each of these issues is important to achieving the overall goal. First, fairness and transparency attract bidders and encourage them to bid aggressively. Second, effective risk measurement and assignment assure that the winning bids will be the bids that mitigate ratepayer risk by placing risk onto the bidder and taking that risk away from ratepayers. Third, if the procurement does not produce a positive final result – contracts actually signed and power actually produced – then the entire process will be of marginal value, as the whole purpose of the RFP is to secure new supply to meet the previously identified need at the lowest risk-adjusted cost for ratepayers given current market conditions. Fourth, the process must be in line with Commission rules and Guidelines since those Guidelines represent the Commission's goals in terms of the type of supply procured and the method by which it is to be procured, and they have been vetted extensively with all stakeholders.

Assessment

The 2009R RFP design is well suited to achieving the goal of getting a good deal for ratepayers. It is fair and transparent in that it is a renewables-only RFP. Because of this, bids will have similar characteristics, which enable the comparison of bids to be done chiefly on the basis of price. A price-only evaluation is the ultimate in transparency as it serves to eliminate some of the subjectivity of bid evaluation. Furthermore, the RFP invites competition from many types of renewable resources and provides clear product definitions.

The RFP manages and assigns risk in a few ways. Most importantly, it attempts to account for the risk that Company benchmark bids are ultimately submitted on a cost-of-service basis instead of a fixed bid basis (as third-party bids are). The specific risk is that the Company bids will end up costing more than predicted in the bidding phase. The RFP manages this risk through "risk-adjusting" the benchmarks (i.e. adjusting the capital costs based on changes in broad market indices). This technique was used in the 2008 All Source RFP and was approved for use in the 2008R-1 RFP (although it ultimately was not used, as the Company did not submit benchmark bids). A second way in which risk is managed is through the Company's ACC analysis, which measures the benefit of renewable generation (via the Company's Planning and Risk (PaR) model) against changes in multiple factors, specifically wholesale energy market prices, gas prices, thermal outages, hydro generation and demand levels.

With regard to producing a positive result, the RFP does not contain any broad participation restrictions or any requirements, such as excessive credit requirements, that would appear to hinder participation and, therefore, lead to a less than optimal result.

Finally, the RFP is in line with the Commission's Competitive Bidding Guidelines. It is based on a need identified during the Company's IRP process, and links to that process through the use of IRP assumptions and models (specifically the PaR model). The RFP provides for resource diversity on the initial shortlist through the use of multiple bid categories. It defers consideration of the controversial "debt equivalence" issue (which assigns theoretical costs to a PPA purchase to make a Company's balance sheet "whole") until after the final shortlist is selected, which contributes to the fairness of the RFP. The RFP also provides draft contracts for bidder review. We do note that, in order to be fully compliant with guidelines regarding the benchmark resources, the

Company will have to submit benchmark resources and scores to the IE prior to opening of third-party bids.

III. COMMENTS ON ADDITIONAL ISSUES

Overlap

The key issue that is present in this RFP but was not in the 2008R-1 RFP is the issue of RFP overlap, specifically, the fact that there may be overlap between negotiations with shortlisted bidders in the 2008R-1 RFP and the receipt and evaluation of bids in the 2009R RFP. PacifiCorp has acknowledged this issue and states that the overlap will "allow the Company to compare the costs from the 2008R-1 RFP with those submitted in the 2009R RFP to ensure that customers receive the least cost resource." At the approval hearing for the 2008R-1 final shortlist on June 16, PacifiCorp stated that contract negotiations with winning bidders from that RFP would take from 3 to 6 months.

As stated in our initial comments, we believe a valid concern of bidders may be that the Company will deliberately delay negotiations with 2008R-1 bidders in order to receive bids in the 2009R RFP. We see three potential concerns. First, delays in contract negotiations could cause bidders to miss promised on-line dates. Second, bidders could be concerned that "losers" of the 2008R-1 RFP now get a chance to re-bid against them. This concern is magnified because a Company benchmark option will now be offered. Third, the fact that the Company is issuing an RFP so soon after the 2008R-1, coupled with the fact that the Company has had difficulty "crossing the finish line" in recent competitive procurement processes, may lead to the idea that these RFPs are simply a way for the Company to "test the market" and not a way to seriously consider offers. Any one of these concerns could harm future participation in PacifiCorp RFPs.

The Commission could deal with this problem by delaying the approval of the 2009R RFP until the Company has completed negotiations with bidders in the 2008R-1 RFP. As we stated in our initial comments, this would not be a preferred option for several reasons. First, this may be an excellent time to purchase renewable resources: the response to the 2008R-1 RFP was very good, the new administration in Washington, DC has been active in pushing for renewable development, and as demand slacks off, other utilities may postpone renewable procurements, making suppliers more eager to make a deal. Second, the Company's 2008 IRP seeks 2,000 MW of renewable resources by 2013, so there appears to be a need for renewable supply beyond the potential 500 MW that the 2008R-1 RFP may bring. Third, contract negotiations, even those conducted in good faith, can drag on for a long period of time, and we would not want to lose this opportunity while waiting for a single project to complete negotiations.

In our initial comments, we suggested that the Company respond to concerns about overlap by including a statement in the RFP that it is committed to following each RFP through to its conclusion and commits to negotiate in good faith toward a conclusion with bidders in the 2008R-1 prior to receipt of bids in the 2009R RFP. This statement was meant to reassure bidders in both the 2008R-1 and 2009R RFPs, while still allowing the Company the opportunity to take advantage of current market conditions.

The Company chose not to respond to this issue in the Final Draft RFP. This fact, coupled with the Company's issues with finalizing competitive procurement processes, gives us concern as to the Company's ultimate intentions. Therefore, we would recommend that the Commission place conditions on the approval of this RFP. First, we recommend that RFP approval be conditioned on the Company's commitment to do what it said it would do in at the 2008R-1 final shortlist approval hearing – negotiate in good faith towards a conclusion in the 2008R-1 RFP within three to six months. We recommend starting this time from the issuance of this RFP, assuming an early July issuance. We further recommend that the Commission augment this condition by requiring the Company to file an update and justification with the Commission as soon it has any indications that one of the following two conditions will occur: (a) negotiations will not be completed within the above time frame or (b) that all bids from the 2008R-1 final shortlist will be dropped from consideration for a final contract.

Since the most damaging occurrence from a point of bidder confidence (and future participation) would be for the Company to reject all of the shortlisted 2008R-1 bids in favor of a Company benchmark without sufficient justification, we would further recommend that the Commission notify the Company in the RFP approval Order that, should this happen, the Company will face substantial public skepticism and should be ready to prove that its benchmark was a clearly superior offer to the shortlisted 2008R-1 bids.

Regardless of the action chosen by the Commission, we believe that the Company should encourage the remaining bidders in the 2008R-1 RFP to submit bids into the 2009R process as a backup in case negotiations for their project fall through. We do not want to see a bidder with a good proposal prevented from participating in the 2009R RFP solely because negotiations with the Company stopped at too late a date to bid into the next RFP.

Credit

The RFP also features one change from the 2008R-1 RFP with regard to credit requirements. In the Draft Model Power Purchase Agreement the Company has slightly changed the definition of a Qualifying Institution, i.e. an institution that may provide a letter of credit for the bidder. In the 2008R-1 agreement a Qualifying Institution was defined as a commercial bank or trust with a net worth of at least $1 billion and a credit rating on its long-term senior unsecured debt of at least “A” by S&P or “A2” by Moody’s. Under the 2009R RFP, a Qualifying Institution must have a net worth <u>net of reserves</u> of $<u>10</u> billion and ratings of at least “A” by S&P <u>and</u> “A2” by Moody’s.

These definitions, while slightly stricter that we have seen in other procurements, are not, in our judgment, so strict that they will greatly restrict the pool of eligible bidders. We do, however, invite comment from other market participants as to whether this revised definition will cause them not to participate.

ATTACHMENT ONE
BOSTON PACIFIC INITIAL COMMENTS AND PACIFICORP RESPONSE

MEMORANDUM

June 4, 2009

TO: Stacey Kusters
PacifiCorp

FROM: Frank Mossburg
Andrew Gisselquist
Sam Choi

SUBJECT: Suggestions for 2009R RFP Design

The purpose of this memo is to provide requested comments and questions regarding the Company's initial draft of the 2009R Renewables RFP. Because the RFP is based on the 2008R-1 RFP, which was heavily debated and received a good amount of participation, and does not feature very many changes from that RFP, we do not have many major changes to suggest at this time. Our chief comments relate to the integration of this upcoming RFP with the current 2008R-1 RFP.

QUESTIONS, COMMENTS AND SUGGESTED CHANGES

Integration with 2008R-1 RFP

Our chief concern is how this RFP will interact with the current 2008R-1 RFP, which is set to come before the Commission on June 16 for acknowledgment of its final shortlist selections. The Company's application to open a docket states "The 2009R RFP may run in parallel with the 2008R-1 RFP for a period of time…this would allow the Company to compare the costs from the 2008R-1 RFP with those submitted in the 2009R RFP to ensure that customers receive the least cost resource."

Our concern, and, we believe, a concern of bidders, is that PacifiCorp will delay negotiations with shortlisted bidders in the 2008R-1 RFP in order to get the results of the 2009R RFP and, potentially, use these results to reject their bids. We think this could hurt competition for several reasons. First, successful bidders in the 2008R-1 RFP could see this as an avenue for their competitors to re-bid projects against them. Second, bidders may see these RFPs as doing nothing more than "testing" the market, as opposed to being real commercial opportunities. PacifiCorp's 2012 and 2008 All Source RFPs did not succeed in procuring any supply so bidders may be skeptical as to whether the Company will actually “close the deal” with a supplier. Third, with the announcement that this RFP will feature a Company benchmark bid, bidders could be concerned that the delay is being used to advantage the self-build option.

In order to remedy these concerns and give bidders in both RFPs some assurance that the opportunities here are real, we see two options.

> Option 1: A statement is added to the RFP that “The Company is committed to following each RFP through to its conclusion and commits to negotiate in good faith toward a conclusion with bidders in the 2008R-1 prior to receipt of bids in this 2009R RFP.”
>
> Option 2: The Commission refuses to acknowledge this 2009R RFP until a conclusion is reached in the 2008R-1 RFP.

Boston Pacific supports Option 1. This statement would become a condition of Commission approval of the 2009R RFP and the Commission could ask to see proof of good faith negotiations at any time. By “proof” we mean items such as (a) e-mails, (b) drafts of contracts, (c) cost/benefit analysis and/or (d) negotiating session presentations. If requested, this proof could be reviewed by the IE in this docket and, should the Commission find the Company did not negotiate in good faith, the remedies could include (a) failure to acknowledge the 2009R final shortlist and/or (b) refusal to acknowledge overlapping RFPs in the future. In short, this statement would reassure bidders in both the 2008R-1 and 2009R RFPs, while still allowing the Company the opportunity to take advantage of current market conditions.

Option 2 would be for the Commission to refuse to acknowledge this 2009R RFP until a conclusion is reached in the 2008R-1 RFP. However, this may be too harsh. Now may be a good time to purchase renewable supply, for several reasons. First, the response to the 2008R-1 RFP was very good and the new administration in Washington, DC has been active in pushing for renewable development. Second, as demand slacks off, other utilities may postpone renewable procurements, meaning that suppliers will be more eager to make a deal. Third, the Company’s IRP seeks 2,000 MW of renewable resources by 2013, so there appears to be a need for renewable supply beyond the potential 500 MW that the 2008R-1 RFP may bring. Fourth, contract negotiations, even those conducted in good faith, can drag on for a long period of time, and we would not want to lose this opportunity while waiting for a single project to complete negotiations.

Regardless of the option chosen we believe that the Company should encourage the remaining bidders in the 2008R-1 RFP to submit bids into the 2009R process as a backup in case negotiations for their project fall through. We do not want to see a bidder with a good proposal prevented from participating in the 2009R RFP solely because negotiations with the Company stopped at too late a date to bid into the next RFP.

Other Comments

We have a number of other comments and questions regarding the RFP document and appendices. Our questions, comments, and suggested changes are provided below in bullet-point format.

Comments on the RFP

- In the 2008R-1 RFP the Company determined that Utah law (S.B 202) required them to issue an RFP in a year in which they would be making renewable acquisitions. This led to a re-issue of the 2008R-1 RFP. Is the Company sure that it can avoid a similar situation by either (a) issuing a separate RFP in 2010 or (b) not acquiring assets in 2010?

- Will the Company plan on using a Utah consultant to oversee the bidding? The choice is up to the Company and Utah regulators. If there is a plan to do so, we would recommend keeping the reference to a Utah consultant (even if a firm has not been selected).

- During the 2008R-1 RFP design process, much discussion was given as to how to handle the unique risks that the benchmarks contain. Ultimately the Commission required the Company to "risk-adjust" the capital costs of the benchmarks (see condition 7 of the 2008R-1 RFP approval). We used the technique in the 2008 All Source and would suggest that it be used here as well. We would simply state in a footnote that "to evaluate the risks of benchmark resources, and consistent with practice in other RFPs, the Company will risk-adjust the benchmarks in the following manner…" and then add the language from condition seven. The footnote could be appended to the end of the second paragraph on page 22, section A.

- Another condition that was required of the 2008R-1 RFP was condition 8, which requested the Company to perform additional analysis if the short-listed bids had positive ACC values. We still think this is a valuable exercise and would recommend including it here, perhaps before Section D on page 28.

- Prior to section D on page 28 we would add that the ACC value will be also examined on an "adjusted" basis with adjustments being made to account for (a) terminal value, (b) locational integration costs and (c) incremental capacity contribution.

- Page 9 has a bullet point which suggests that a bidder can submit a PPA not backed by an asset for a term of less than 5 years. This should be removed.

- Page 14 seems to suggest that there will be only two shortlists, wind and non-wind, later the number of shortlists is three (east wind, west wind and non-wind). We assume that there will be three shortlists, consistent with the 2008R-1.

- Page 14 also suggests that 500 MW may be taken to the shortlists, as opposed to 500 MW or 5 bids. We would suggest the latter standard, again, consistent with the 2008R-1.

- Where wind power is requested to provide back-up for estimated MWh of production, so too should other intermittent technologies such as solar. For example, see Appendix B, p. 3.

Comments on Appendices

- Appendix B, p. 5 – Bidders objecting to contract terms should be encouraged to provide suggested alternate language or at least some context for their objection. Having bidders simply mark which sections they find objectionable provides little to no evidence of how significant any changes they may request will be.

- Appendix K, section 2)a. and 4)c. – These sections imply that the IE will necessarily be involved in every communication between the utility and bidder as such communications are occurring. Instead, the role of the IE in these communications should be described as in Appendix L, that the IE will be "included" in communications.

- Appendix L, "Integrated Resource Planning Team (IRP)" section – what is the justification for deleting the requirement that "Any information the IRP group obtains from the Benchmark Team on Benchmark Resources will not be shared with the Origination or Structuring and Pricing work groups until after the final shortlist is determined"? Similarly, what is the justification for removing similar wording in the Benchmark Team section of Appendix L?

- Appendix L, "Intent to Bid Team" section – the IE is required to provide Bidders with some information after the Bidders qualifications have been discussed. What is meant by this section?

- Appendix L, “Marketing Affiliate Employees” and “Shared Employee” sections – what is the justification for removing Marketing & Trading Contracts and Structuring and Pricing groups from the list of Marketing Affiliate Business Units of PacifiCorp (which will allow employees in these groups to see confidential transmission system or marketing information)?

- Draft PPA, Section 1 Definitions; Rules of Interpretation – The “or” replaced by “and” in the definition of “Qualifying Institution” should be reinstated. We have seen in other procurements that requiring that a Qualified Institution has a particular credit rating from both S&P and Moody’s may remove banks that are credit worthy, but simply are not rated by both institutions.

- Draft PPA, Section 4.5 – what would happen if the requirement that a seller maintain CRS Green-e good standing throughout the contract was violated? Would the answer to that question change if the lack of good standing was due to a change in the Green-e program definitions or if the Green-e program was discontinued?

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A DIVISION OF PACIFICORP

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Boston Pacific
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RE: In response to the Memorandum dated June 4, 2009 from Frank Mossburg, Andrew Gisselquist and Sam Choi.

The Company has made the following changes to the 2009R RFP to reflect the suggestions made by the Oregon Independent Evaluator:

In the 2008R-1 RFP the Company determined that Utah law (S.B 202) required them to issue an RFP in a year in which they would be making renewable acquisitions. This led to a re-issue of the 2008R-1 RFP. Is the Company sure that it can avoid a similar situation by either (a) issuing a separate RFP in 2010 or (b) not acquiring assets in 2010?

Yes the Company will manage its requirements under SB 202.

Will the Company plan on using a Utah consultant to oversee the bidding? The choice is up to the Company and Utah regulators. If there is a plan to do so, we would recommend keeping the reference to a Utah consultant (even if a firm has not been selected).

The Company will not have a Utah consultant.

During the 2008R-1 RFP design process, much discussion was given as to how to handle the unique risks that the benchmarks contain. Ultimately the Commission required the Company to "risk-adjust" the capital costs of the benchmarks (see condition 7 of the 2008R-1 RFP approval). We used the technique in the 2008 All Source and would suggest that it be used here as well. We would simply state in a footnote that "to evaluate the risks of benchmark resources, and consistent with practice in other RFPs, the Company will risk-adjust the benchmarks in the following manner…" and then add the language from condition seven. The footnote could be appended to the end of the second paragraph on page 22, section A.

A footnote has been added to address the risk-adjustment to benchmark resources. This is an item that the Company would like to have further discussion with the Independent Evaluator, since it was not used in the 2008R-1.

Another condition that was required of the 2008R-1 RFP was condition 8, which requested the Company to perform additional analysis if the short-listed bids had positive ACC values. We still think this is a valuable exercise and would recommend including it here, perhaps before Section D on page 28.

The Company has added a statement that it may perform additional analysis if the initial shortlist bids have positive ACC. We would like to see the results of such an analysis in the 2008R-1 to determine the value of time and work required to perform such analysis prior to putting the obligation in the request for proposal.

Prior to section D on page 28 we would add that the ACC value will be also examined on an "adjusted" basis with adjustments being made to account for (a) terminal value, (b) locational integration costs and (c) incremental capacity contribution.

A section was added in the 2009R RFP to incorporate the recommendation to examine the "adjustments" for a) terminal value, b) locational integration costs and c0 incremental capacity contribution.

Page 9 has a bullet point which suggests that a bidder can submit a PPA not backed by an asset for a term of less than 5 years. This should be removed.

Page 9 – deleted the bullet point which suggests that a bidder can submit a PPA not backed by an asset for a term of less than 5 years.

Page 14 seems to suggest that there will be only two shortlists, wind and non-wind, later the number of shortlists is three (east wind, west wind and non-wind). We assume that there will be three shortlists, consistent with the 2008R-1.

Page 14 – clarified that there are three shortlists.

Page 14 also suggests that 500 MW may be taken to the shortlists, as opposed to 500 MW or 5 bids. We would suggest the latter standard, again, consistent with the 2008R-1.

Page 14 – add that the initial shortlist will contain 500MW or 5 bids.

Where wind power is requested to provide back-up for estimated MWh of production, so too should other intermittent technologies such as solar. For example, see Appendix B, p. 3.

Request for back up estimated MWh of production is a requirement for all proposals not just wind. We will address this clarification in the Pre-bid meeting and adjust in the final documents as there are areas in the RFP that would also need to reflect this change.

Appendix B, p. 5 – Bidders objecting to contract terms should be encouraged to provide suggested alternate language or at least some context for their objection. Having bidders simply mark which sections they find objectionable provides little to no evidence of how significant any changes they may request will be.

Appendix B, p5 – language was added to encourage bidder to provide suggested alternate language and context for their objections.

Appendix K, section 2)a. and 4)c. – These sections imply that the IE will necessarily be involved in every communication between the utility and bidder as such communications are occurring. Instead, the role of the IE in these communications should be described as in Appendix L, that the IE will be "included" in communications.

Appendix K, section 2a and 4c have been deleted and replaced with a section that references the IE role as indicated in Appendix L.

Appendix L, "Integrated Resource Planning Team (IRP)" section – what is the justification for deleting the requirement that "Any information the IRP group obtains from the Benchmark Team on Benchmark Resources will not be shared with the Origination or Structuring and Pricing work groups until after the final shortlist is determined"? Similarly, what is the justification for removing similar wording in the Benchmark Team section of Appendix L?

Appendix L – the justification for the deletion is that the Evaluation Team is responsible to complete the evaluation of the Initial Shortlist for the Benchmark resource. Previously, we did not include the Benchmark in the Initial Shortlist however we did in the 2008R-1 after clarification with the Oregon Staff.

Appendix L, "Intent to Bid Team" section – the IE is required to provide Bidders with some information after the Bidders qualifications have been discussed. What is meant by this section?

Appendix L – This was deleted.

Appendix L, "Marketing Affiliate Employees" and "Shared Employee" sections – what is the justification for removing Marketing & Trading Contracts and Structuring and Pricing groups from the list of Marketing Affiliate Business Units of PacifiCorp (which will allow employees in these groups to see confidential transmission system or marketing information)?

Appendix L – Shared Employees can see confidential transmission system and can not provide the confidential information to Market Affiliates. Structuring and Pricing and Marketing and Trading previously were classified as Market Affiliates and are now considered Shared employees, pursuant to FERC Order 717 (October 16, 2008).

Draft PPA, Section 1 Definitions; Rules of Interpretation – The "or" replaced by "and" in the definition of "Qualifying Institution" should be reinstated. We have seen in other procurements that requiring that a Qualified Institution has a particular credit rating from both S&P and Moody's may remove banks that are credit worthy, but simply are not rated by both institutions.

Draft PPA – Definitions; rules of Interpretation – the Company has raised its credit standards for a Qualifying Institution in light of market events over the past several months. Also, the correct language in the PPA should read, and will be corrected in the Final RFP to read as follows:

"Qualifying Institution" means the United States office of a commercial bank or trust company organized under the laws of the United States of America or a political subdivision thereof, or a foreign bank, with a net worth of at least $10,000,000,000 (net of reserves) and a credit rating on its long-term senior unsecured debt of at least "A" by S&P and "A2" by Moody's.

Draft PPA, Section 4.5 – what would happen if the requirement that a seller maintain CRS Green-e good standing throughout the contract was violated? Would the answer to that question change if the lack of good standing was due to a change in the Green-e program definitions or if the Green-e program was discontinued?

Draft PPA, Section 4.5 - Seller would be in violation of the agreement and would need to cure it. If there are no Green-e standards, the Seller would be obligated to the successor program of the successor entity (see Section 1.2.1(c)). If there is no successor program of a successor entity, the same contract interpretation principles apply that would resolve, for example, the last sentence of Section 6.6.2 should the standards and criteria of Electric System Authority are no longer applicable.

Sincerely,

Stacey Kusters

cc: Andrew Gisselquist
Sam Choi

ATTACHMENT TWO

BOSTON PACIFIC COMMENTS ON PACIFICORP'S 2008R-1 RENEWABLES RFP DESIGN

THE OREGON INDEPENDENT EVALUATOR'S ASSESSMENT OF PACIFICORP'S 2008R-1 RENEWABLES RFP DESIGN

PREPARED BY

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July 3, 2008

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I. EXECUTIVE SUMMARY

A. INTRODUCTION

Boston Pacific Company, Inc. was chosen by the Public Utility Commission of Oregon (the Commission) to serve as the Independent Evaluator (IE) for PacifiCorp's 2008 R-1 Renewables RFP (2008R-1 RFP or the RFP). This report represents Boston Pacific's analysis of the Final Draft of the 2008 R-1 RFP filed on March 4, 2008. The purpose of this report is to identify areas of concern regarding RFP design and to recommend areas where PacifiCorp could improve the RFP in order to get a better result for ratepayers.

B. BACKGROUND

When appraising the design of any competitive procurement process Boston Pacific begins with the goal of the procurement. The goal is to get the best deal possible for ratepayers in terms of price, risk, reliability and environmental performance given market and regulatory conditions. To know if a process will satisfy this goal we look to answer four key questions. These are: (a) Is the process fair and transparent? (b) Does the process properly measure and assign risk? (c) Will the process likely lead to a positive result? and (d) Does the process comply with the regulatory rules and guidelines, including the Commission's Competitive Bidding Guidelines?

The right answers to each of these four questions are important to serving the overall goal. First, fairness and transparency attract bidders and encourage them to bid aggressively. One cannot have competition without competitors and the more competitors the better the chance ratepayers will get a good deal. Second, effective risk measurement and assignment assure that the winning bids will be the bids which mitigate ratepayer risk by performing the best under a variety of possible future scenarios; that is, they are the best deal for ratepayers given the major uncertainties facing us in the future. Risk assignment also encourages bidders to assume risk, rather than pushing risk on to the ratepayers. Third, if the procurement does not produce a positive final result – contracts actually signed and power actually produced - then the entire process will be of marginal value, as the whole purpose of the RFP is to actually secure the lowest risk-adjusted cost supply for ratepayers. Fourth, the process must be in line with Commission rules, especially Competitive Bidding Guidelines (the Guidelines). Those Guidelines represent the Commission's goals in terms of the type of supply procured and the method by which it is to be procured, and they have been vetted extensively with all stakeholders.

For a more detailed discussion of these topics, why they are important, and how to achieve them in RFP design, please see Appendix A.

C. SUMMARY OF FINDINGS

Boston Pacific reviewed the 2008R-1 RFP with the above four questions as a guide. Our findings are summarized below, grouped according to the question addressed. Detailed discussions of each of these issues are found in the body of this report.

Fairness and Transparency

As background, note that the Company's evaluation methods for the initial and final shortlists rank each bid by a calculation of *net benefits*. Put simply, the net benefits of each bid are calculated by subtracting (a) the cost of a given renewable supply, (i.e the cost of a bid) from (b) the avoided cost – that is, the forecasted cost of buying power to replace the renewable supply. In the initial shortlist analysis, avoided cost is calculated using the Company's forward price curve – PacifiCorp's forecast of market prices. In the final shortlist evaluation, this net benefit measure is known as the Alternative Compliance Cost (ACC). In the ACC method, avoided cost is calculated by comparing cost estimates from two runs of the Company's Planning and Risk (PaR) model, one with and one without uncommitted renewable resources.

Our chief concern is that the ACC method understates the value of renewables in two ways. First, it calculates avoided costs of renewables using only a single estimate of future carbon emissions costs. A secondary concern is that it does not directly reflect a value for Renewable Energy Credits (RECs); note that REC value is reflected in the Company's IRP, as are multiple levels of future CO_2 emissions costs. Because all bids will produce RECs and all bids will avoid carbon emissions, these concerns do not cause any real problem so long as PacifiCorp uses the ACC only to rank bids. PacifiCorp must not, however, use the ACC analysis results to justify taking less than its 500 MW need. If PacifiCorp wishes to use the ACC analysis to justify taking less than 500 MW it must re-run the analysis with different CO_2 emission costs levels (per its IRP) and take into consideration REC values that reflect values assigned to RECs in the IRP process adjusted for consideration of Renewable Portfolio Standards in Oregon and other states. This adjustment should include consideration of factors such as levels and timing of renewable requirements, market composition, current PacifiCorp renewable supply, Alternative Compliance Payments, availability of RECs on open markets, potential market value, and the "bankability" and "saleability" of RECs.

We have three other points related to fairness and transparency.

- Because PacifiCorp's Benchmark bids will be submitted on a cost-of-service basis they will not be comparable to third-party bids and will shift more risk to ratepayers. This extra risk must be accounted for in bid evaluation.

- PacifiCorp should clarify what it means when it requires each bidder to hold an "option" to purchase turbines or other long lead-time equipment. PacifiCorp must hold its Benchmark bids to the same standard.

- On a positive note, fairness and transparency are served well by several aspects of the RFP including: a clear definition of products solicited; multiple fuel and transaction types solicited; no consideration of debt equivalence in the shortlist evaluations; complete and, with some exceptions as noted below, generally acceptable Power Purchase Agreement (PPA) and Build Own Transfer (BOT) contracts; and a clear connection to the Company's IRP process.

Addressing Uncertainty and Assigning Risk

With regard to risk measurement and assignment our chief concern is that the RFP does not attempt to assess the extra risk assigned to ratepayers in the Benchmark bids. Methods to accomplish this task include "risk-adjusting" bids, "PPA-like" agreements, cost "bands", and "cap and no floor" offers. All are discussed in the text herein.

In addition, PacifiCorp should take a different approach to assess the risk of extension or removal of the Production Tax Credit. We suggest that it create two final shortlists, one assuming extension of the credit and one assuming removal of the credit. PPA bidders should be allowed to specify binding prices for futures with and without the Production Tax Credit.

PacifiCorp's analysis gives bidders credit for generating more energy in peak periods. However it does not capture capacity value, including value due to diversity of location. We recommend that the Company investigate a way to capture this benefit.

Again, on a positive note, the Company's ACC method does nicely take into account the risk of key market variables like natural gas prices and wholesale power costs. It also accounts for key costs and benefits such as wind integration costs.

Producing a Positive Result

PacifiCorp will not achieve a positive result if it deters or rejects good bids for the wrong reason. Typically, the wrong reasons are reflected in broad threshold requirements. As a threshold requirement, PacifiCorp requires a PPA bidder to offer to sell its power facility to PacifiCorp at the end of the term for one dollar. This should be changed so that an asset sale is an option and the price offer is set by the bidder. If it is not changed, we believe it could lead to fewer bidders and higher prices in this RFP. Moreover, a mandatory asset sale undermines the Commission's goal of creating a competitive market since it takes away the opportunity for competitors to become established in renewables supply.

We have five other points here.

- Credit requirements often are a concern for bidders and a barrier to producing a positive result. PacifiCorp's credit requirements, while assuming a "worst-case" view of the future, are in line with previous RFPs.

- To address concerns about uncertain construction costs, PacifiCorp allows bidders in other RFPs to index capital costs for new construction. However, indexing for capital costs is not allowed in this RFP for renewables. This appears to be justified by differences in the nature of equipment and labor needed for construction and shorter lead-times required for renewable resource construction. We did not hear bidder objection to the lack of indexing in this proceeding.

- PacifiCorp should either explicitly prohibit non-asset backed bids from participating or eliminate the prohibition against bundling wholesale market purchases with RECs, which is likely the only way in which these bids can participate.

- The current bid fees are acceptable, but, if bidders wish to alter them, PacifiCorp should consider the use of a "partial success" fee whereby initial bid fees are reduced, but not eliminated, and the winning bidder pays the remaining administrative costs for the RFP.

- The requirement for maintaining Green-e certification of all RECs should be made optional. Such a requirement may prevent some facilities from bidding that would otherwise be eligible.

Compliance with Commission Guidelines

The Commission's Guideline 9a requires consideration of resource diversity on the initial shortlist. PacifiCorp is already accounting for resource diversity by holding a separate RFP for renewables and inviting multiple technology types to bid. Nevertheless, in order to more fully comply with this Guideline, PacifiCorp should create separate wind and non-wind categories for the initial shortlist.

Two other points are relevant here.

- PacifiCorp's Benchmark must identify the sites of Benchmarks to be in compliance with Guidelines 4 and 8.

- In order to be in compliance with Guideline 6, PacifiCorp must provide a draft asset sale agreement.

II. DETAILED DISCUSSION OF THE RFP

The following is a review of specific items in the RFP. This review is focused on our four evaluation criteria: (a) fairness and transparency, (b) risk measurement and assignment, (c) producing a positive result, and (d) compliance with appropriate Commission guidelines.

A. FAIRNESS AND TRANSPARENCY

1. The Company's method for evaluating bids for the final shortlist is called the Alternative Compliance Cost (ACC) method. Our primary concern is that it does not reflect the full potential value of renewables because it does not take into account a full range of future emissions-regulation costs and the direct value of RECs. This is acceptable if the Company uses the ACC results only to rank individual bids, but not if it is used to reject them as a group.

To discuss PacifiCorp's bid evaluation process we must first explain it using some relatively simple examples. The actual process is more complicated, but the general principles are the same.[1] It is best to discuss the initial and final shortlists separately.

Initial Shortlist

PacifiCorp's price evaluation begins with its initial shortlist screen. For this screen, PacifiCorp calculates the net benefit of each bid. Simply put, the net benefit equals (a) the avoided cost of the bid, *plus* (b) value of the RECs produced by the bid *less* (c) the bid's cost. All of this is done on a per megawatt-hour basis.

The avoided cost used here represents the cost of purchasing power from the wholesale market at prices based on PacifiCorp's forward price curve. The REC value is taken from PacifiCorp's latest IRP ($5 per MWh for the first 5 years of operation of the asset) and amortized over the life of the asset. The bid costs are either (a) the PPA prices as provided by the bidder or (b) capital revenue requirements plus operating and maintenance costs in the case of a BOT, Benchmark or asset sale.

To get a sense of what this calculation looks like, we provide an example of a hypothetical PPA bidder who offers pricing at $65 per MWh in peak hours and $60 per MWh in the off-peak. We use hypothetical avoided cost prices and a simple value of $5/MWh (extended through the life of the bid and unamortized) for RECs. The relevant calculations are displayed in Table One.

[1] Our interpretation of the Company's bid evaluation method comes from discussions with the Company and examination of multiple "mock bids" which we created and which were evaluated by PacifiCorp.

TABLE ONE
INITIAL SHORTLIST PRICE EVALUATION EXAMPLE[2]

Year	Forward Price Curve Avoided Cost (Per Mwh)		REC Value	Generation (MWh) (Provided by Bidder)		Total Avoided Cost (Avoided Cost plus REC value)	Bidder Cost (Provided by Bidder)		Total Bidder's Cost	Net Benefit
	Peak	Off-Peak	(per MWh)	Peak	Off-Peak		Peak	Off-Peak		
2010	$ 45	$ 32	$ 5.00	25,000	20,000	$ 1,990,000	$ 65	$ 60	$ 2,825,000	$ (835,000)
2011	$ 50	$ 45	$ 5.00	27,500	22,000	$ 2,612,500	$ 65	$ 60	$ 3,107,500	$ (495,000)
2012	$ 60	$ 50	$ 5.00	30,250	24,200	$ 3,297,250	$ 65	$ 60	$ 3,418,250	$ (121,000)
2013	$ 62	$ 53	$ 5.00	33,275	26,620	$ 3,773,385	$ 65	$ 60	$ 3,760,075	$ 13,310
2014	$ 63	$ 55	$ 5.00	36,603	29,282	$ 4,245,890	$ 65	$ 60	$ 4,136,083	$ 109,808
2015	$ 74	$ 63	$ 5.00	40,263	32,210	$ 5,371,051	$ 65	$ 60	$ 4,549,691	$ 821,360
2016	$ 85	$ 70	$ 5.00	44,289	35,431	$ 6,643,354	$ 65	$ 60	$ 5,004,660	$ 1,638,694
2017	$ 88	$ 75	$ 5.00	48,718	38,974	$ 7,648,715	$ 65	$ 60	$ 5,505,126	$ 2,143,589
2018	$ 90	$ 78	$ 5.00	53,590	42,872	$ 8,649,381	$ 65	$ 60	$ 6,055,638	$ 2,593,742
2019	$ 92	$ 79	$ 5.00	58,949	47,159	$ 9,679,375	$ 65	$ 60	$ 6,661,202	$ 3,018,173
2020	$ 95	$ 80	$ 5.00	64,844	51,875	$ 10,893,718	$ 65	$ 60	$ 7,327,322	$ 3,566,396
2021	$ 106	$ 85	$ 5.00	71,328	57,062	$ 13,053,009	$ 65	$ 60	$ 8,060,055	$ 4,992,954
		Totals		534,607	427,686	$ 77,857,628			$ 60,410,602	$ 17,447,026
					Per MWh	$ 80.91			$ 62.78	$ 18.13

The net benefit of the bid in this simple example is a positive $18.13 per MWh. This is calculated by dividing the total Net Benefit ($17,447,026) by the total generation (534,607 MWh plus 427,686 MWh, or 962,293 MWh total). Net benefit per MWh will be used to calculate the initial price score of the bids, and therefore, rank the bids. This, of course, greatly oversimplifies the calculation, primarily because the Company actually discounts the avoided costs, bid costs and MWh back to the present day, as opposed to using the simple totals as in this Table. Also note that the Company will add benefits to the bid for Production Tax Credits and add to the bid the cost of items such as third-party transmission services and wind integration.

Final Shortlist

To select bids for the Final Shortlist, PacifiCorp plans to employ the Alternative Compliance Cost (ACC) method. The ACC method is actually very similar to the initial shortlist screen. In essence, the ACC method also attempts to calculate the net benefits of a renewable resource. Bids which generate the most net benefits on a per MWh basis will be selected for the Final Shortlist.

Rather than looking to the forward price curve to calculate avoided costs, the Company uses its Planning and Risk (PaR) model. The Company first runs PaR with the preferred portfolio from its latest IRP (updated through the Company's IRP Update, including resources selected or under consideration in dockets UM-1374 and UM-1360).[3]

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[2] The formulae for the calculations are as follows: (a) Total Avoided Cost equals Forward Price Curve Avoided Cost plus REC value multiplied by Generation; (b) Total Bidder Cost equals Bidder Cost multiplied by Generation; and (c) Net Benefit equals Total Avoided Cost less Total Bidder Cost.

[3] Use of the IRP Update is important because the update significantly changed the Company's preferred portfolio. Specifically, it removed new coal resources to reflect the non-viability of these resources. This change should result in a more accurate avoided cost calculation then a calculation which assumes cheaper new coal generation exists. Use of potential new generation under consideration is also appropriate.

This establishes a baseline value for the portfolio by looking at the average cost of 100 separate, least-cost dispatch solutions which each represent different assumptions about natural gas prices, wholesale market prices, load, hydro generation levels, and thermal outages. The Company then removes uncommitted (i.e. proxy) renewable resources from the portfolio and re-runs the PaR model. The model estimates the costs to replace the removed renewable resources via least-cost dispatch by purchasing from the spot market and running available generation as it sees fit. These additional costs are divided by the MWh replaced (i.e. the MWh that the uncommitted renewable resources had generated) to determine the dollar-per MWh avoided costs of renewable resources.

As an example, let us say that, in one hour, the original PaR run includes 200 MWh of wind-generated energy. In the second PaR run this 200 MW is replaced by a combination of 100 MWh of generation from gas-fired plants, which cost $70 per MWh, and 100 MWh of market purchases, costing $80 per MWh. Thus, the avoided costs for the renewable resources in this hour are $75 per MWh. This calculation is “rolled up”, or grouped by year, month and peak or off-peak period.

As seen in Table Two, the Net Benefits are calculated in the same way as in the initial shortlist. The Net Benefits of the bid are calculated as (a) the PaR generated avoided cost *less* (b) bid costs. Note that a REC value is not inserted here. The ACC value is the value that, on a per-MWh basis, makes the net benefits equal *zero*. In this example, that is calculated by taking the negative of Total Net Benefits divided by Total Generation (in the actual method present values are used).

TABLE TWO
ACC PRICE EVALUATION EXAMPLE

Year	PaR Generated Avoided Cost (Per Mwh)		REC Value	Generation (MWh) (Provided by Bidder)		Total Avoided Cost	Bidder Cost		Total Bidder's Cost	Net Benefit
	Peak	Off-Peak	(per MWh)	Peak	Off-Peak		Peak	Off-Peak		
2010	$ 48	$ 30	$ -	25,000	20,000	$ 1,800,000	$ 65	$ 60	$ 2,825,000	$ (1,025,000)
2011	$ 53	$ 48	$ -	27,500	22,000	$ 2,513,500	$ 65	$ 60	$ 3,107,500	$ (594,000)
2012	$ 62	$ 51	$ -	30,250	24,200	$ 3,109,700	$ 65	$ 60	$ 3,418,250	$ (308,550)
2013	$ 65	$ 55	$ -	33,275	26,620	$ 3,626,975	$ 65	$ 60	$ 3,760,075	$ (133,100)
2014	$ 66	$ 56	$ -	36,603	29,282	$ 4,055,557	$ 65	$ 60	$ 4,136,083	$ (80,526)
2015	$ 70	$ 64	$ -	40,263	32,210	$ 4,879,845	$ 65	$ 60	$ 4,549,691	$ 330,155
2016	$ 88	$ 72	$ -	44,289	35,431	$ 6,448,482	$ 65	$ 60	$ 5,004,660	$ 1,443,822
2017	$ 90	$ 77	$ -	48,718	38,974	$ 7,385,638	$ 65	$ 60	$ 5,505,126	$ 1,880,512
2018	$ 95	$ 75	$ -	53,590	42,872	$ 8,306,407	$ 65	$ 60	$ 6,055,638	$ 2,250,768
2019	$ 96	$ 73	$ -	58,949	47,159	$ 9,101,678	$ 65	$ 60	$ 6,661,202	$ 2,440,476
2020	$ 98	$ 81	$ -	64,844	51,875	$ 10,556,532	$ 65	$ 60	$ 7,327,322	$ 3,229,209
2021	$ 101	$ 85	$ -	71,328	57,062	$ 12,054,418	$ 65	$ 60	$ 8,060,055	$ 3,994,363
		Totals		534,607	427,686	$ 73,838,732			$ 60,410,602	$ 13,428,130
					Per MWh	$ 76.73			$ 62.78	$ 13.95
									ACC	$ (13.95)

In this example the ACC value is negative $13.95 per MWh. If we reverse the valuation (from negative to positive) this represents the net benefits of the bid per MWh of generation. The bids for the final shortlist will be ranked by ACC value. Again, this example vastly oversimplifies the actual calculation, which will, as the initial shortlist screen did, incorporate discounting of MWh, avoided costs and bid costs. Also, as in the initial shortlist, benefit will be added for Production Tax Credits and costs will be added for factors such as wind integration and third-party transmission.[4]

Our Concerns

As far as a general tool for ranking renewable resource bids, the Company's methods are acceptable. However, when it comes to assessing the true net benefits of renewable resources, the ACC method has two questionable omissions. The first omission results from not testing the full range of future CO_2 emissions costs, as in the IRP. While the PaR model, as noted, examines changes in many variables to produce its avoided cost estimates, it only uses one estimate of future carbon dioxide emissions compliance costs (about $8 per ton of CO_2). The Company's IRP uses future emissions costs ranging from up to $61 a ton to select resources for the future (we note that the latest IRP Update introduces a "cap and trade" structure). Higher levels of CO_2 taxes will only serve to make renewable resources more valuable.

The second omission, made obvious in our example above, is that the ACC method does not include any explicit value for Renewable Energy Credits (or Green Tags). The reason for this is mechanical. In order to calculate the precise point at which the net benefits of the bid are zero the ACC model alters one input cell over and over until the model is "balanced." The input that gets altered *is* the REC value. In other words, the ACC model generates an *implied* REC value. Because of the amortization and discounting of RECs, this implied REC value will not equal the ACC value, but it will be in the same magnitude and direction. In other words, a positive ACC means a positive implied REC value (and vice-versa) and a relatively large ACC means a relatively large implied REC value (and vice versa).

The value of generating an implied REC value is understandable from an analytical standpoint. It acknowledges that renewable resources have some additional value above and beyond their cost and the avoidance of future CO_2 emissions costs. The source of this value derives from state RPS standards which allow utilities to generate, buy and sell RECs to satisfy their requirements and penalize utilities who do not live up to RPS standards. The question the ACC method tries to answer is "what additional value do I have to place on renewable generation in order for me to be indifferent between (a) using this renewable resource and (b) purchasing from the wholesale market?" The more costly a bid (holding the avoided cost steady) the more additional value we have to place on renewable generation in order for it to make economic sense to purchase generation from renewable resources.

[4] A few other points to emphasize

- For an actual bid evaluation this calculation will be discounted back to the present using the company's post-tax cost of capital as a discount rate.
- The PaR-generated avoided cost calculation does *not* change from bidder to bidder.
- The bidder provides one year of peak and off-peak generation along with costs (either capital costs for BOTs or per MWh energy costs for a PPA).

From the perspective of selecting the top ranked bids, these omissions are acceptable. All the technology types solicited will avoid CO_2 emissions and will provide RECs. Therefore adjusting for these values should not change the rankings of bids. However, we have a concern that the ACC values will be held as a real measure of the value of renewables and, if no bids show a net savings, the results of this analysis will be used to reject bids, and thereby, take less than the 500 MW of resources that the Company is seeking.

This is problematic primarily because, as noted, higher CO_2 cost estimates will only increase the value of renewables, and renewables do have additional value because of RPS rules. In addition, not taking a full complement of resources without examining the resources against the full range of CO_2 emissions costs and potential REC benefits could be seen as a violation of the Commission's bidding Guidelines, which direct the utility to evaluate bids consistent with the IRP process.

While we recognize that the Company has the right to reject bids, we believe that more analysis must be done if the Company wishes to justify complete rejection of all bids based on the ACC results. We would recommend that in the event the Company wants to take less than 500 MW of resources for the Final Shortlist, it must first re-run the ACC analyses using all CO_2 emissions cost levels from the 2007 IRP. When re-examining the results the Company must also consider the implied REC values from the ACC analysis and compare them to REC values which reflect values assigned to RECs in the IRP process adjusted for consideration for Renewable Portfolio Standards in Oregon and other states.

By adjusting for RPS standards we mean that the Company should re-assess the IRP-derived REC value in consideration of RPS factors in the states it serves. For each state these factors would include renewable generation requirements, market composition, current PacifiCorp renewable supply, Alternative Compliance Payments, the predicted availability of RECs on open markets, the potential cost of those RECs, the "bankability" or ability to store RECs and the ability to sell RECs.

2. PacifiCorp's cost-of-service Benchmarks create evaluation problems and give the Company an advantage over other bidders.

PacifiCorp may submit self-build options, so-called "Benchmark Bids" into the RFP. These bids will be up to three wind energy projects of up to 300 MW each with a location yet to be determined, but likely in Wyoming.

The chief issue surrounding the Benchmark bids is the issue of comparability. By this we mean that third-party bidders must propose binding bids for PPAs or BOT contracts, while the Benchmark bids will simply be estimates. While the IE will review the Benchmark costs to determine if they are reasonable the Company will be able to recover whatever costs it expends to construct them (subject to a prudence review). This shifting of risk to ratepayers represents an advantage for the Company and creates problems for evaluators.

The ideal solution to this problem would be for the Company to agree to comparability. PacifiCorp would create an unregulated subsidiary to construct and manage the project. The subsidiary would be related to PacifiCorp's ultimate parent company to limit the impact on local ratepayers if the subsidiary suffers financial difficulties. Most importantly, the subsidiary would agree to a fixed-price PPA with performance guarantees. This would have the benefits of (a) protecting ratepayers from cost overruns and (b) attracting more bidders, since bidders would understand that all bids are on a "level playing field." This approach is used today in unit-contingent RFPs (e.g. Public Service Oklahoma's 2008 baseload RFP).

We have yet to hear a substantive reason as to why this cannot be achieved. Typically, concerns are raised about the possibility that a utility could earn more than its regulated return, but the same is true with any performance-based ratemaking and that is certainly nothing new. Moreover, if the deal offered by the affiliate represents the best risk-adjusted price for Oregon ratepayers in a healthy competition, why is profit an issue? Other concerns are raised about the utility's obligation to serve ratepayers, but, in our opinion, the picking of winners in the RFP satisfies that obligation.

Nevertheless, based on previous work with the Company we understand that PacifiCorp will not likely change its stance on this issue anytime soon. Therefore, within the evaluation, we will have to find some way to assess the extra risk that the Benchmark bids place on ratepayers. Our strategies for doing this are detailed later in this report.

3. PacifiCorp should clarify what it means by an "option" to purchase turbines or other long lead-time equipment, and hold its Benchmark bids to the same standard.

In the RFP, PacifiCorp declares that it may disqualify bids which do not show a "contractual right or an option" to purchase wind turbines or other long-lead time equipment. Because this could represent a major hurdle for bidders we think it is important for the Company to clarify what it means by a "contractual right or option".

We certainly understand that the markets for many pieces of equipment feature long lead times and that the Company wants resources by the December, 2011 deadline. However, we also recognize that bidders may reasonably disagree on what sort of advance preparations are required heading into this RFP and we do not want to needlessly restrict the bidding pool. Therefore, we would also encourage any input from bidders as to what they believe constitutes a reasonable "option" to purchase equipment.

More importantly, however the Company ultimately does define an "option" we recommend that the Benchmark bids should be held to that very same standard. This comparability will serve to more closely match the risk profiles of third-party bids and the Benchmarks. As we discuss later, to the extent the Company has obtained fixed price commitments on their equipment, that will serve to reduce the risk of the Benchmarks to customers and can be factored into our evaluation of the Benchmarks.

In conversations, the Company has expressed some concern about recovery of costs should it acquire wind turbines and then fail to be selected in this RFP. We will leave that decision up to the Commission; however we will note that every other bidder faces this cost recovery risk. We can suggest that if the Company is worried about this outcome, they could reduce this potential risk by eliminating the option requirement and also by allowing bidders to offer sites-only bids for wind generation.

4. With some exceptions, PacifiCorp's standard form contracts are generally acceptable.

With the chief exception of the mandatory-offer clause in the standard form PPA and the fact that the PPA does not contemplate pricing based on futures "with" and "without" PTC extension, the standard form contracts provided by PacifiCorp are generally acceptable. We note that bidders will have opportunities to negotiate these contracts after final shortlist selection.

The contracts provided are wind-specific. PacifiCorp has stated, in data request responses, that bidders with non-wind projects will not be penalized in the initial shortlist evaluation for failure to conform to the standard contracts, unless their changes "alter the risk profile" for the bid. This appears to be an acceptable position.

5. The RFP has positive features in respect to fairness and transparency.

The RFP does have some positive features with respect to fairness and transparency. First and foremost, the RFP only invites bids for renewables. This will simplify the job of comparing bids with vastly different risk profiles (no one will have to compare, for example, a wind plant versus a coal facility), moving the evaluation a bit closer to a "price only" evaluation. Second, the RFP allows for multiple types of renewables, from wind energy to solar power to biomass and geothermal facilities. Third, multiple transaction styles are allowed, from PPAs to BOTs to sales of existing assets.[5] Fourth, the RFP connects to the Company's IRP process; both the amounts requested and the PaR models used to calculate the net benefits for renewables are from that process. Fifth, the issue of debt equivalence, per Commission Guidelines, is not considered in the shortlist evaluations. In service of this last issue PacifiCorp will remove a reference to bid disqualification due to "consolidation on the utility's balance sheet." While we believe that this was intended to refer to Variable Interest Entity (VIE) treatment, other parties believe that it referred to the lease classification under debt equivalence issue, so the Company will remove it to avoid confusion.

[5] We note that existing assets are not considered in the draft RFP, but PacifiCorp has promised, in a data request response, to include these as an option in the final RFP. This appropriately reflects our own recommendation in Docket UM-1374 regarding allowing existing assets to participate in RFPs.

B. ADDRESS UNCERTAINTY AND ASSIGN RISK

1. PacifiCorp's current evaluation process does not take into account the differences in risk between transaction types. Therefore some measure of this risk must be made.

All things being equal, we prefer to see bids that shift risks from ratepayers to the seller, who is almost always in a better position to manage risks. Thus, any bid evaluation method must assess the ways in which each bid allocates risk. One flaw in PacifiCorp's current evaluation process is that it does not recognize the risks inherent in each transaction type. The general risk profile of each transaction can be laid out as follows:

- PPAs: Most risks are shifted to the seller, including capital cost risk (i.e. the risk of cost overruns) and operating cost risk.

- BOTs and Sales of Existing Assets: These shift capital cost risk from ratepayers to the seller (or do away with it all together). But, since PacifiCorp will operate the assets on a cost-of-service basis, these agreements shift most of the risk for operating cost overruns to ratepayers.

- Benchmark Bids: As discussed above, Benchmark Bids shift the most risks to ratepayers. Both capital cost risk and operating cost risk are assigned to ratepayers.

In order to properly evaluate bids, some measure of these risks must be accounted for in the bid evaluation. Based on our previous work, we can suggest four basic strategies. We are flexible as to the final method chosen as well as the specifics of that method.

First, the Company could work with regulators and interested parties to create a before-the-fact "PPA-like" document, which would set cost recovery at the Benchmark price. Operating performance standards should also be set based on the assumptions in the Benchmark.

Second, the Company could submit a percentage "band" around its Benchmark price estimate which would serve as a cap and floor (or "collar") on cost recovery. The Company would set the band value (e.g. 5%, 10%) and the Benchmarks would be evaluated on the highest-case scenario, that is, PacifiCorp would have its Benchmark evaluated with its prescribed upper band (5%, 10%) included.

Third, the Company could submit, in addition to its Benchmark bids, a "ceiling" bid that will be completely binding, creating, essentially a "cap and no floor" situation. The bid could initially be evaluated on the "best guess" cost but would also be analyzed under this “upper cap” offer to see the potential impact of cost overruns. If selected, the Company’s project would be paid at cost-plus, subject to this cap.

Fourth, in the evaluation process, evaluators could reflect the added risk of the benchmark bids by adding a specified amount to (i.e. “risk-adjusting”) capital costs to reflect the possibility of cost overruns. For example, the Company’s bid could be indexed 50% to the Consumer Price Index (CPI) and 50% to the Producer Price Index – Metals (PPI). Those indices would then be assumed to escalate at their mean projected escalation rate *plus* the 95th percentile of their expected value *times* the probability of occurrence (i.e. 5%). For example, if the CPI and PPI-metals have an average projected escalation of 5% and a 95th percentile value of 10% (i.e. the indices have a 5% chance of being over 10%), then the Risk-Adjusted escalation would be 5.5%. (5.5% equals 5% plus .05 times 10%). The Benchmark’s capital costs would be inflated by this percentage and this inflated value would be used for evaluation purposes. This final method will be used in the Company’s upcoming 2008 All Source RFP.

While our main concern in this analysis is capital costs, we also believe that, for completeness sake, we should make the same risk adjustment for operating costs. Because operating costs are likely to follow the CPI, and because there has not been a large amount of historical volatility in the CPI, this will likely not have a significant impact. Nevertheless, we think that it would be a good step for the sake of an accurate evaluation.

2. PacifiCorp’s evaluations must take into account the possibility of the removal of the Production Tax Credit by ranking bids with and without the Credit. PacifiCorp must allow PPA bidders a chance to bid with and without PTC prices.

The Production Tax Credit (PTC) represents an important source of value for renewable resources. Currently, wind, solar, geothermal, and “closed loop” biomass facilities receive a 2.0 cents per kWh (or $20/MWh) tax credit for every kilowatt-hour generated in the first ten years of a facility’s existence. Other facilities (such as open-loop biomass, small irrigation and landfill gas) receive a credit of 1.0 cents per kWh ($10/MWh). The PTC is due to expire at the end of this year, but the possibility remains that it could be extended.

In the RFP as written, PPA bidders must absorb all of the risk for expiration of the PTC. In other words, they cannot propose one price, then return and change their price if the PTC is not renewed. BOT bids and Benchmarks will pass on this risk to ratepayers. Presumably, if the PTC is not renewed PacifiCorp will request that the lost benefit be recovered in rates. This difference will give an advantage to the Benchmarks and BOT bids.

As noted above, PPAs are a good risk management tool because they shift risk away from ratepayers to bidders. The reason this is a good thing is because bidders are often poised to manage risks, like the risks of overruns in construction costs, far better than ratepayers.

However, that line of reasoning does not hold for the PTC. The PTC is a political risk that bidders have very little control over. In this way it is very much like the risk of federally-mandated carbon emissions costs. In previous baseload RFPs PacifiCorp allowed bidders to pass through these costs.

Because the PTC is so large, and because there is little way to hedge it, we are concerned that the current RFP will lose PPA bidders, who will not wish to take on such a large risk that they can neither hedge nor predict. We think that it would be a mistake to remove these potential bidders from competition, particularly when BOTs and Benchmarks do not offer any better risk protection for ratepayers.

Other renewables RFPs have allowed bids contingent on the PTC extension. For example two 2008 AEP renewables RFPs "[expect] to make extension of the PTC a Condition Precedent to effectiveness of any agreement." Both Arizona Public Service and PG&E have had recent renewable RFPs in which bidders were allowed to submit two bids – one if the PTC was extended, and one if it was not.

Another difficulty surrounding PTC extension is that it creates confusion among bidders. Some bidders price their bids assuming an extension, while other bidders choose not to do so. In order to be as clear and accurate in our analysis as possible, we propose that PPA bidders be allowed to submit two bids, one assuming the PTC is extended, and one which assumes PTC expiration. If the PTC does expire, the bidders would get the latter price and PacifiCorp would have permission from regulators to recover the higher price.

The initial and final shortlist evaluation would be conducted on a "with/without" analysis, ranking the bids (and Benchmarks) with and without PTC extension. If the rankings differ, the IE and PacifiCorp will confer and select the final shortlist of bids based upon bid performance in both analyses. We will look for facilities which can perform reasonably well under both circumstances in order to make the best price and risk tradeoff for ratepayers.

3. PacifiCorp's methods only partially account for locational differences in assets and do not account for capacity values.

As noted by the Company in its IRP, the capacity contribution of wind resources can vary by location, and the incremental capacity contribution of wind resources declines with each new resource added to the area. Resources in different areas, which run at different times, could, in theory produce more of a capacity benefit than two resources in the same area. In the IRP, the Company uses an analytical method based on the "Z statistic" to calculate the capacity contribution of wind resources and select a portfolio of proxy resources.

The Company's evaluation methods in this RFP do not value the capacity contribution of bids *per se*. However, bids that are offered into this RFP can gain advantages from their location if, because of better wind conditions, they operate more in peak hours and months. Bids which generate more in peak times will produce more avoided cost benefit than bids which do not.

We agree that renewables can have a capacity benefit and that locational diversity can provide incrementally more capacity benefit. As noted above, the IRP process, which guides the acquisition amounts in this RFP, does take into account capacity benefits and locational diversity. The only reason to factor these values into the bid evaluation process would be if we believe it will change the bid rankings. In other words, we would include it if it helped us know if we should take a bid with a lower net benefit (as calculated in the ACC method) due to its higher capacity contribution. In order to make this decision we need to put a dollar value on this capacity contribution.

Presently, there is no easy way that we know of to accurately calculate this dollar value. We note that the value is likely to be smaller relative to the net benefits calculated in the ACC method. Nevertheless, in order to more accurately value bids we would recommend that the Company explore ways of calculating this benefit and implement a chosen method in this RFP. We would be happy to assist in this effort.

4. PacifiCorp's ACC method does account for the risk of several key variables, including natural gas prices.

The ACC method does account for risks of several key variables. In calculating the net benefits generated by renewable resources PacifiCorp's PaR model reflects changes in gas prices, hydro generation levels, wholesale market prices, load, and thermal outages. It also, as mentioned, accounts for third-party transmission and other costs and benefits, such as wind integration costs.

C. PRODUCE A POSITIVE RESULT

Even with a completely fair and transparent process we still must consider whether there are any threshold requirements or contractual terms which otherwise deter or eliminate bidders so that the RFP will not produce a positive result for ratepayers.

1. Due to its potential detrimental effects on bidder participation and long-term competition we would recommend that the end-of-term asset purchase offer be made optional.

The current PPA makes it mandatory for bidders to offer their asset to PacifiCorp at the end of the contract for on dollar. In conversation and in response comments the Company has indicated that this is intended to make PPAs comparable with BOT and Benchmark offers. The Company believes that, since BOT and Benchmark offers will have some value at the end of their life (due chiefly to the site value), forcing PPAs to also explicitly include this value will make them comparable.

We appreciate the Company's efforts to enforce comparability. However, we would argue, as we have above, that comparability would be best served by the Company bidding as a third-party bidder with a fixed, pay-for-performance PPA.

Our concern with this requirement is threefold. First, that it could, in fact, lead to bidders refusing to participate. Second, that from a competitive policy standpoint, this will ensure that competitors are removed from the market at the end of the contract term, and that PacifiCorp will own most of the prime renewable resource sites. Third, that the forced handover of assets for a minimal fee will lead to bidders raising their prices to compensate for the lost site value.

We do not see any rationale for requiring competitors to turn over prime sites to PacifiCorp. This was not a requirement in the 2012 or 2008 All Source RFPs, and we fail to see why it should be here. Most importantly, from a standpoint of competitive policy, why would the Commission allow a contract which forces the elimination of established competitors? Oregon cannot have competition without competitors, and it cannot have strong competitors if it does not allow them to get a foothold in the market and to build from there.

In terms of comparing PPAs to BOTs or Benchmarks we find that it would be more reasonable to give some end-of-life benefit to a BOT or Benchmark than to force PPA bidders to sell their site and assets to PacifiCorp. The issue remains as to what an end-of-life value should be for a BOT or Benchmark. Predicting the value of any asset twenty years from now is particularly difficult, especially assets whose value depends so much on regulations (e.g. carbon emissions taxes, Performance Tax Credits). We do note, however, that the standard form PPAs provided with the RFP set the salvage value of a renewable resource at $1. Therefore, to be consistent, the Company, should have to use $1 for an end-of-term BOT and Benchmark value. If, however, PPA bidders are allowed to and do offer higher prices for site purchase options, then the Company may adjust their salvage values upward based on these numbers.

In conversations with other parties and the Company there has been some concern that the purchase requirement would trigger Variable Interest Entity (VIE) treatment. We do not believe this to be the case. In our minds, VIE treatment involves the absorption of gains or losses by the purchasing entity (i.e. PacifiCorp). In other words, a VIE treatment would occur if PacifiCorp agreed to adjust the end-of-term purchase price to guarantee bidders a certain return. A flat rate purchase price and a minimal payment do not meet this test.

2. PacifiCorp's credit requirements assume a "worst case" scenario for replacement power costs, but are, nonetheless, generally reasonable and in line with previous Company RFPs.

Another key area that can have a chilling effect on RFP participation, and thus endanger the chances of a positive result, is excessive collateral requirements for bidders. PacifiCorp sets the maximum collateral requirements by assuming that, if a bidder backs out of an agreement, PacifiCorp will need 18 months to find replacement supply. Then, for the 18 month period PacifiCorp forecasts an upper range or "stressed" price of wholesale power, specifically they find the price at the 84th percentile of the distribution of possible prices. In other words, the Company calculates a price that, based on current projections and past price volatility, will be equal to or higher than the actual wholesale market price 84% of the time. PacifiCorp then subtracts from this stressed price the average predicted wholesale market price for the same time period (which serves as a proxy for bid cost). The difference is an estimate of exposure per MWh. The exposure per MWh is the potential added cost of market purchases if a bidder fails to perform as promised. This is multiplied by the number of MW bid to set the total possible exposure to higher prices.

It is important to see that, this method is something of a "worst-case" scenario. It assumes that *in every hour for 18 months* that the bid is out of service the Company will pay this 84th percentile "stressed" value. By contrast, the Company's 2012 Base Load and 2008 All Source RFPs only focus on the summer months.

This "worst-case" assumption is tempered somewhat by the fact that most bids will not generate very many MWh (compared to the baseload units solicited in other RFPs), so the overall collateral amounts required are lowered. Another, more important point, is that the collateral amounts required in this RFP match the Company's 2008R Renewables RFP, which drew a reasonable number of bidders. Also the portion of the exposure that has to be covered by collateral varies with the credit rating of the bidder. Higher credit ratings mean lower collateral requirements.

While we generally believe that the collateral requirements are reasonable, we would always welcome feedback from bidders with alternate proposals.

3. The decision not to allow indexing of capital costs for new-build bids is reasonable, so long as bidder feedback does not indicate that it will hinder participation.

In this RFP for renewables PacifiCorp will not be allowing bidders to "index" or tie the capital cost of their bid to broad, public cost indicators. This represents a significant change from the 2012 Base Load RFP and 2008 All Source RFPs, in which bidders were allowed to index up to 40% of the capital costs of a new facility to the Consumer Price Index (CPI) and Producer Price Index –Metals (PPI-metals).

In the absence of bidder comment to the contrary, we believe that not allowing indexing in this RFP is an appropriate measure for three reasons. First, we understand renewables are different from traditional baseload resources in multiple ways: they can have shorter lead times for equipment, use less sophisticated equipment and labor, and developers will often have some store or inventory of uncommitted turbines on order. This means indexing is less important to renewables developers. Second, in our other monitoring engagements for renewable resources we have not seen a fixed-price requirement become an issue. Third, fixed prices offer a protection to ratepayers by forcing bidders to assume risk and manage their projects more efficiently.

4. The prohibition against a bid which bundles wholesale market purchases with RECs means that, in all likelihood, non-asset backed bids cannot participate in this RFP.

The RFP allows bidders to offer non-asset-backed power sales of less than five years in duration. To our minds, the only way that a bidder without a designated asset could provide the RECs that the Company requires in this RFP would be to bundle those RECs with wholesale market energy. However, this strategy is prohibited by Section 5(G) of the RFP, which states that the Company is only interested in "proposals that offer *both* Renewable Energy Credits (RECs) and underlying generation from an associated Renewable Resource."

We think that it would be acceptable to allow only asset-backed bids, particularly in light of the RPS requirements which may mandate them. In fact, if RECs bundled with market purchases were allowed we might have to think of some way to account for the fact that, by our reading, those RECs might be less valuable than RECs from asset-backed bids. In Oregon, RECs acquired separately from renewable energy may only account for 20% of renewable compliance after 2020. In California, RECs are currently not allowed without the generation to back them up.

The Company either must either explicitly prohibit non-asset-backed bids or explicitly allow bids which bundle RECs with market purchases.

5. While we accept the bidders fee as it stands, a possible alternative, in order to better align fees with differing cost recovery methods, may be a hybrid model combining a reduced bid fee and a success fee.

Currently, bidders wishing to participate in the 2008R-1 RFP must pay a bid fee of $10,000. Bidders may submit two alternatives bids in addition to a base bid. The purpose of the bid fee is twofold: (a) to pay for the IE costs of reviewing the bids, and (b) to remove non-serious or frivolous bids from the analysis. It has been pointed out that the current structure may raise problems because the recovery of IE costs in Utah is supposed to be covered by the bid fee, while in Oregon the IE costs are to be recovered in rates. This could lead to Oregon ratepayers paying slightly higher bid prices (as bidders up their costs to recover bid fees) and paying again if the Company recovers IE costs in base rates.

Ultimately, Boston Pacific believes that the bid fees, which were also used in the 2012 Base Load RFP, are acceptable as written. A $10,000 cost is not small, but in the context of a $200 million capital cost for a new facility it is minimal, particularly when we consider that part of the bid fee will go to paying the Utah consultant.

However, if the Company and regulators wish to more accurately reflect the split in Oregon and Utah recovery methods we would recommend that the Company explore an alternative path. In this alternative, PacifiCorp could lower the bid fee to better reflect only the Utah IE charges, then recover the remainder of IE costs with a "success fee" whereby the winner of the RFP pays the administrative costs of the RFP (subject to a cap). If this path is taken, care should be taken not to change the fee structure in any way that would potentially reduce the number of bidders.

6. The requirement for maintaining Green-e certification of all RECs produced may prevent some facilities from bidding that would otherwise be eligible and should be made optional.

The requirement currently in the PPA that bidders maintain registration with the Center for Resource Solution's Green-e program appears to disallow certain renewable fuel types that the RFP specifies as eligible. Specifically, Green-e eligibility standards require that facilities were placed in operation on or after January 1, 1997, as opposed to the comparable date in the RFP of January 1, 1995. Additionally, current Green-e National Standards do not allow wave, tidal or ocean thermal facilities to qualify for Green-e certification and may not allow some hydropower projects that are intended to be eligible in this RFP.[6] It is our understanding that PacifiCorp is requiring Green-e certification only to provide itself with a larger market in which to sell excess RECs. Given that RECs from facilities not eligible for Green-e could still be sold, though perhaps for a slightly lower price, we believe it would be appropriate for PacifiCorp to modify the RFP to remove the requirement for Green-e certification and instead, in the case of a tie, give preference to bidders who have shown that their facility will qualify for Green-e certification.

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[6] Green-e National Standard, Version 1.5, modified 07/20/1007, www.green-e.org

D. COMPLIANCE WITH COMMISSION GUIDELINES

1. Guideline 9a requires that selection of the initial shortlist provide resource diversity. While resource diversity is served nicely by holding a separate renewables RFP, we would recommend the added step of having the initial shortlist broken into wind and non-wind bids.

Guideline 9a of the Commission's Competitive Bidding Guidelines states that selection of the initial shortlist of bids should "provide resource diversity." Staff has raised the question as to whether the Company's evaluation process will accomplish this goal. In our opinion, a great deal of the Commission's goal of diversity has already been accomplished. By having separate RFPs for renewables and other resources the Company is taking steps to ensure that it will procure both fossil fuel and renewable resources, in line with its IRP.

In addition, the 2008R-1 RFP solicits bids from a wide range of fuel types, so a diverse set of renewable bidders will be invited to bid. We think it may be helpful to ensure that some of this diversity makes it at least to the initial shortlist process. However, because there are so many renewable fuel types, allowing bid rankings by fuel type might result in too many bids making it to the final shortlist. This could be done by taking the highest ranked bids from each fuel type. Because we expect a majority of bidders to be wind-based we think it may achieve the Commission's goals if we were to create two bid categories, one for "wind" and one for all "other" renewable fuels. The top bids in each of these two categories would be placed on the initial shortlist.

2. PacifiCorp's Benchmark must disclose sites for Benchmark resources in order to comply with Guidelines 4 and 8.

Staff has raised the question of whether the amount of disclosure provided to bidders regarding PacifiCorp's Benchmark bids is sufficient. Currently, PacifiCorp states that the Benchmarks may be "up to three wind projects", on "up to three sites", and "up to 300 MW per project." Locations include "sites the Company is currently developing in Wyoming."

In terms of matching with Guideline 4, a Benchmark Resource is defined as a "site-specific, self-build option." We read this to say that PacifiCorp's current level of disclosure falls short because they do not provide a specific site. However, we understand that, should the Company choose to officially submit a Benchmark resource, they will identify the site to bidders when they submit the resource to the IE to be evaluated, approximately two weeks before bids are due. We find this acceptable and, in fact, necessary. Per Guideline 8, the Company must submit initial scoring for the Benchmark models at the same time it submits the Benchmarks to the IE for evaluation, and that initial scoring must reflect a specific project proposal.

3. In order to be in compliance with Guideline 6, PacifiCorp must provide a draft asset sale agreement.

Guideline 6 requires that the final draft RFP submitted to the Commission include standard form contracts. So far PacifiCorp has provided documents relating to BOTs and a model PPA. Because, as we understand it, the Company will be allowing bidders to offer sales of an existing asset, the Company should also provide a standard form of an asset sale contract so that bidders can understand what type of agreement they will be signing.

APPENDIX A
KEY CRITERIA OF RFP EVALUATION

KEY CRITERIA OF RFP EVALUATION

Our starting point in reviewing any RFP is the basic premise that the purpose of any competitive solicitation should be to get the best deal possible for ratepayers in terms of price, risk, reliability, and environmental performance, given current market and regulatory conditions. In evaluating whether or not the RFP will lead to this goal we have found it helpful to focus on four key questions: (a) Is the process fair and transparent? (b) Does the process properly measure and assign risk? (c) Will the process likely lead to a positive result? and (d) Is the process compliant with the Commission's regulatory rules and guidelines?

Following is a brief primer as to why these questions are important and some ways in which to achieve positive answers to these questions.

A. FAIRNESS AND TRANSPARENCY

Why is it important?

To achieve a positive outcome for ratepayers the methods of bid and Benchmark evaluation must be fair and transparent to all. Fairness means that all parties are treated equally. This includes not only third party bids, but also utility Benchmark or self-build options. Transparency means that all parties can understand the RFP requirements and evaluation methods. Only if fairness and transparency are present will a large number of competing power suppliers participate and bid aggressively.

Fairness and transparency attract bidders for several reasons. First, because a solicitation is "fair" bidders know that their bid will be considered on equal footing with other bids, they do not have to worry about their bid losing out to an inferior offer. Second, because a process is transparent bidders know exactly what is being solicited and how bids will be evaluated. When bidders know that no special privilege will be granted to any bidder and evaluation criteria are laid out clearly they know that aggressive bidding is the only way to ensure that they win the RFP.

Fairness and transparency also benefit ratepayers. The more bidders, bidding aggressively, that are in the RFP, the better chance the ratepayers have of receiving a quality offer. Transparency also has the added benefit of letting the ratepayers know just how the winning bids were chosen.

How do we achieve it?

There is no single right way to solicit power and, therefore, there is no single right way to achieve fairness and transparency. In general, a fair and transparent process would involve; (a) all parties bidding under the same terms, (b) a precisely defined product, and (c) a price only or "price mostly" evaluation. The point of these conditions is to make sure that all bidders understand what they are bidding for and how they will be evaluated and that the winner will simply be the bidder who offers the best deal for ratepayers.

An example of these principles in action can be seen in the full requirements solicitations for Standard Offer or Basic Generation Service in PJM. The product for these auctions is precisely defined as full requirements supply which, in essence, makes each supplier responsible for serving a percentage share of the energy, capacity, and ancillary service needs of a ratepayer class. Bidders offer an amount of supply at a stated price. The winners are simply the bidders who offer to supply at the lowest cost. All bidders, including the utility affiliate, are treated in the same manner and sign the same contracts.

This is not meant to suggest that PacifiCorp must conduct a full-requirements type solicitation, only to provide a real-world demonstration of fairness and transparency. We feel that it is important for parties to understand that these are more than just "principles" but standards that are achievable in the real world.

B. MEASURING AND ASSIGNING RISK

Why is it important?

In reviewing RFPs we look for an evaluation process which, to the best extent possible, recognizes the uncertain nature of the future, that the only thing certain is uncertainty. Today, future values of variables such as gas prices, emissions regulations, and construction cost escalations are unknown. Yet these variables will have a great impact on future ratepayer costs. The impact of new technology could also greatly affect the choice and cost of future supply.

If the exact paths of these variables were known, the selection of new resources would be relatively easy. In reality, there are no certainties about the future, which makes the evaluation process much more complex. The best evaluation process is one which acknowledges the risks that ratepayers face, and incorporates an analysis of those risks into the selection of bids which perform well under many different future scenarios.

The RFP, then, must do two things to take account of risk. First, the evaluation methods must recognize and measure risk. Second, bids must be credited to the extent that they assign risk away from the ratepayers and onto parties better equipped to manage risk.

This focus also assists ratepayers because, if the evaluation clearly accounts for risk, then credit can be given to the bidders who act to shield ratepayers from risk and the lowest-risk bids can be identified. It also encourages innovative risk management. If bidders know that they will stand a greater chance to win, all things being equal, by removing risks from the ratepayer, then they will be encouraged to come up with ways to remove or hedge risk.

How do we achieve it?

To find the best deal for ratepayers, risks must be accurately measured in the evaluation process. There are two chief ways to handle this task. One way is to assign each bidder the same risk profile through a tightly defined product, process, and a contract which holds all bidders to the same risk assignment standard. This method is used in the previously-mentioned full requirements solicitations in areas like New Jersey and Delaware, where all bidders, including utility affiliates, bid by the same rules for the same product and sign standardized contracts.

The second way to measure risk is to review the key risks inherent in each bid and attempt to value each of them separately. This requires sophisticated modeling techniques which model what costs would be incurred for each bid based on changes in key variables. This sort of modeling can take two basic forms, "scenario" modeling or "stochastic" modeling. Scenario modeling examines a single "path" for a given variable and reports what ratepayers would pay given that scenario. Stochastic modeling involves essentially creating multiple "paths" for each variable, basically hundreds of scenario runs at once, which give both an average or expected value of the bid as well as a risk metric such as standard deviation.

The ultimate goal of these exercises is to compare bids with different risk profiles. This comparison is key because the nature and extent of risk varies across technologies and transaction types. For example, for coal-fired technologies the greater risks are linked to capital costs and environmental regulations. In contrast, for natural gas, fuel price risk is the more prominent risk. Similarly a fixed price pay-for-performance power purchase agreement puts all risks on the bidder, while a cost-plus transaction puts the risk burden on the ratepayer.

C. LEADING TO A POSITIVE RESULT

In reviewing and conducting an RFP, it is always important to keep the end goal in mind, the acquisition of the best deal for ratepayers in terms of risk, reliability, price, and environmental performance, given market conditions. The above prescriptions should aid in that goal, but they do not guarantee it. If, for example, a bidding requirement, say, a credit threshold, disqualifies a wide selection of potential participants, then the likelihood of a good result is lower. With this in mind we also review an RFP with an eye toward items which could affect the participation levels in the RFP.

We note that there are times when the goal of a positive result could come into conflict with the other goals mentioned above. For example, a bidder could present an offer that is attractive, but features a non-fixed (or indicative) price. At this point, it is up to the evaluators to decide whether allowing this bid to be evaluated is appropriate given the fact that other bidders have conformed to the requirement to submit a binding bid. In these cases Boston Pacific views part of the IE's job as providing advice on moving forward in the best interests of ratepayers.

D. COMPLYING WITH COMMISSION RULES AND GUIDELINES

A final topic that we review is compliance with appropriate Commission regulatory rules and guidelines. These are usually in line with the goals of fairness and transparency and, of course, are geared toward producing a positive result. We cannot, however, simply ignore rules and guidelines because they represent the will of regulators and the ratepayers, having been vetted through a public comment process. Therefore, any RFP must be reviewed to ensure that it is in compliance with all appropriate rules and guidelines.

MEMORANDUM

August 22, 2008

TO: Lisa Schwartz
Oregon PUC

FROM: Craig Roach
Frank Mossburg
Andrew Gisslequist

SUBJECT: Supplemental Comments of the Independent Evaluator

The purpose of this memo is for the Oregon Independent Evaluator (IE) to provide additional comments in response to PacifiCorp's revised draft 2008R-1 RFP as filed on July 28, 2008, and related commentary. We break our comments down into several sections based on key issues; (a) Mandatory Asset Purchase Option, (b) Production Tax Credit, (c) Capacity Value, (d) Right to Purchase Equipment, and (e) Other Issues.

ISSUE-BY-ISSUE COMMENTS

Mandatory Asset Purchase Option

PacifiCorp continues to request that all bidders who offer a Power Purchase Agreement (PPA) must include a clause that grants the Company a purchase option for the facility in question at the end of the contract term. While PacifiCorp set the purchase option amount at $1 in its initial draft filing they have since altered the draft PPA to allow the bidder to specify the price to be paid for the asset at the end of the contract term.

The IE continues to believe that requiring a purchase option is not in the best interest of Oregon ratepayers and will only serve to raise prices to ratepayers and reduce competition. This could happen in at least four ways.

- First, the mandatory offer requirement will directly increase bid prices. The bidder will have to be compensated for relinquishing their asset after the contract has ended. The bidder will either increase their contract price or ask for a high price for the forced asset sale at the end of the contract. As a result, the ratepayers pay more for a contract than they otherwise would or the purchase decision is changed to an offer that would be more expensive absent the asset sale requirement.

- Second, the mandatory offer requirement could increase costs to ratepayers by preventing quality competitors from offering into the RFP in the first place. A bidder with a quality asset now must give up that asset if they wish to participate in this RFP. Given this choice, bidders may elect not to participate at all, and thus deprive ratepayers of quality offers (and lower prices).

- Third, the mandatory offer requirement could hurt future competition by removing players from the market. Any winners from this RFP will be forced to give up their assets to PacifiCorp. Thus, future RFPs will have fewer competitors, fewer quality choices, and possibly higher prices, for ratepayers.

- Fourth, given that this is envisioned to be an RFP that will be reissued as the Company sees fit to fulfill future needs, a mandatory offer requirement could discourage future competitors from developing renewable assets in the market. No bidder with an interest in developing a continuing, long-term, operating portfolio will want to develop projects in PacifiCorp's territory, knowing that they will only have to turn those over to the Company at some point or another. Again, this could raise future costs to ratepayers by depriving them of quality choices and lower prices.

The only potential benefit to the mandatory asset purchase option is that ratepayers might get a good deal on a renewable asset site twenty to twenty five years from now.[1] That is, a bidder could guess wrong and offer an asset price that is lower than the actual asset value in the future. In our view, this speculative benefit does not outweigh the above drawbacks and the measure is likely to simply lead to increased costs for ratepayers in the near term.

Because of its chilling effect on competition and thus, the resulting increase in prices, mandatory asset purchase options are not common. They are not in PacifiCorp's major supply side RFPs and they are not in renewables RFPs from producers such as Duke Energy Ohio, SWEPCO, PNM and APS.

A solution that has been mentioned is to remove the mandatory nature of the purchase option clause for PPAs and, instead, assign some end-of-life or

[1] Twenty years is the Company's 2007 IRP estimate of a wind project's life span.

salvage value benefit to BOTs and Benchmark bids. While this solution is somewhat of an improvement, it still has problems. While we agree that there is some end-of-life or salvage value to a renewable asset (typically from the site) it is extremely difficult to state this value with any certainty twenty years ahead of time. This is particularly true when the asset value is so dependent on legislation (such as the Production Tax Credit and Carbon Emissions legislation) to drive value. PacifiCorp states that the value is "substantial" but we again note that their original offer price was $1. Furthermore, as Renewable Northwest Project (RNP) notes in their comments, site values are different depending on the nature of the permitting and lease agreements in the proposal.

The danger with this proposal is that it could improperly tilt the selection decision. If evaluators attach a significant salvage value to BOTs and Benchmarks we could end up selecting an asset that is *more* expensive over a twenty or twenty-five year period in the hope that we "guessed right" and that salvage values really are high. Because of this difficulty we think that the salvage value of BOTs and Benchmarks should only have a "tiebreaker" effect on the asset purchase decision. PPA bidders would, of course, be free to offer asset purchase options if the wished, but these too would only have a "tiebreaker" effect.

In conclusion, rather than include a clause which will cause higher prices and competitive harm, or try to accurately value an asset twenty years from now, a far simpler way to benefit customers is to hold a competitive RFP which invites a wide range of bidders, and simply pick the bid which offers the best deal for the specified contract term. This assures that ratepayers will get the best deal, allows competition to grow, and increases the chances of quality offers in the future.

Production Tax Credit

PacifiCorp continues to request that PPA bidders be solely responsible for any change in the status of the Production Tax Credit (PTC). They claim that this requirement places the bidder in a "symmetrical" position with the Company, apparently because the Company can only recover incurred costs.

As noted in our original RFP Design Report, the great strength of contracts is that they allocate risks to those parties who are best equipped to manage that risk. The risk of PTC extension is not within the control of bidders so it makes no sense to ask them to manage that risk when they can do nothing about it. For this reason renewables RFPs often make some allowance for changes in the PTC.

Furthermore, we completely fail to see how forcing a bidder to take the risk of PTC extension puts it in a "symmetrical" position to the Company. In fact, it places the PPA bidder at a detrimental position to BOT bidders and Company Benchmarks, which can simply pass this risk on to ratepayers. Allowing bidders to specify a "with and without" PTC price (as we have suggested) would, in fact, be the way to make symmetrical positions, as well as assure transparency and place PPA bids on equal footing with Benchmarks and BOT bids. This would have the added benefit of allowing those bidders who *are* willing to take on some risk to do so and thus, provide an advantageous bid.

Given that we are allowing "with and without" pricing it makes sense that PacifiCorp should also be required to analyze the performance of bids on a "with and without" basis. This would also seem to be proper, given that the PTC has yet to be extended and would also reveal the benefits of any PPA that wished to assume PTC risk by offering a low price in the "without" scenario.

Capacity Value

Staff and the IE have raised concern that the proposed ACC method does not take into account capacity values. In our RFP Design report we suggested that PacifiCorp devise some method for valuing capacity for this RFP. This would yield two benefits (a) it would give more benefit to resources such as geothermal or biomass facilities and (b) it would create a more complete account of the value for all resources.

We welcome any method that the Company wishes to propose. For our part, in order to assist in this effort we would make the following suggestion. First, PacifiCorp could assign a capacity amount to all resources based upon the methods used in the 2007 IRP. For wind resources, this would include a value based on location, as laid out in Appendix J of the 2007 IRP. Second, convert this capacity amount into a dollar value by multiplying the amount times the annual carrying cost for a new combustion turbine. This value, too, could come from the IRP, so as to be as transparent as possible. This calculation could be added into the ACC model for each month, discounted back to the present day, and divided by the net MWh, just like all other costs and benefits.

We note that the Company appears to think that this method has no analytical evidence to support it. Again, we welcome other proposals from the Company, however, we would note that the carrying cost of a new combustion turbine is a common measure for the value of new capacity, representing as it does the cheapest source of new capacity available to a market. For example, this cost is often used to set the maximum level of price offers in market mitigation situations, on the theory that prices should at least be able to rise to a level that attracts new investment in a market.

Right to Purchase Equipment

In our RFP Design report we requested clarification on PacifiCorp's requirement that a bidder show a right or an option to purchase turbines or other long lead-time equipment; in this context we also requested comments from interveners. RNP stated that, to them, the definition of an option was not a concern, so long as PacifiCorp was held to the same standards. PacifiCorp now states in the RFP that bidders must have a "contract to purchase major equipment (i.e. wind turbines) and a process to adequately acquire other critical long lead time equipment." PacifiCorp further claims that its Benchmark bids should not be held to the same standards as other bidders since these bidders are large developers and the Company has "fewer viable alternatives" for the sale of equipment should it not win the RFP.

While we agree that some bidders may have a larger array of options for turbine use than the Company we don't believe that all bidders are necessarily so advantaged. Given the active market for wind turbines we don't think that holding PacifiCorp to the same standards as a bidder places an undue risk burden on the Company. Moreover, if bidders have a true competitive advantage due to the bidder's broader involvement in wind generation, that should not be a factor that gets blunted by PacifiCorp.

If the Company is truly worried about this risk, we would suggest that it eases it's definition of "option" to one which the Company can live up to. Alternatively, as we mentioned and Staff re-iterates, the Company could accept site-only bids and use their turbines for these sites.

Other Issues

In addition to these four major issues, there are several other issues that we take note of. Other comments are presented in bullet-point form below.

- We note that the Company has not commented in depth on some of our major proposals, chiefly, for (a) what to do if the ACC method results in the Company not taking it's full 500 MW of need and (b) risk-adjusting the Company Benchmarks to account for their cost-plus prices as compared to the fixed prices of the bidders. The Company only states that it will not "change the two-step evaluation process" and may issue further RFPs as needed. The Company has not stated why it should ignore the CO_2 emissions costs levels from the IRP or the potential value of RECs generated by renewable assets should it choose not to take the full 500 MW. Nor does it state why Benchmark bids should not be assessed some sort of penalty for their cost plus nature, which causes higher risks for ratepayers. We continue to hold to our recommendations laid out in our RFP Design Report.

- Staff asks for comment on the level of success fee proposed by PacifiCorp. A potential one million dollar success fee may not be very much in the context of the overall bid cost. For example, a 100 MW wind project will likely have a capital cost of almost $200 million. However, it is very high compared to industry standard bid fees, and thus we fear it may deter bidders from participating. We again invite bidder comment on the issue.

- We believe the proposed non-price factors are generally sufficient; though we welcome bidder comments where definitions are unclear. As an additional measure, we would suggest that the metric "realism of net output projections" be included within the "operational viability" category. Since bidders will be estimating their generation, we think it is proper to have some way of penalizing bids which make unrealistic estimations.

- We have reviewed what we believe to be the draft asset purchase agreement. PacifiCorp did not provide the document in it's filing, but rather refers to an Appendix which points to a previously provided document entitled "Wind Development Asset Acquisition and Sale Agreement." This document was provided in the Company's initial filing and reviewed in our RFP Design Report. In general we find it to be satisfactory, through, as always, we welcome feedback from participants.

- The Company states that "Up to 500 MW" will be taken on each initial shortlist for the wind and non-wind categories of bids. We would suggest that the "ceiling" number be raised to 1,000 MW. The reason for this is that projects may be up to 300 MW in size. This could lead us, particularly in the wind category, with only two or three bids making it to the initial shortlist. This, in our opinion, would not be the sort of supplier diversity that is required on the initial shortlist. Note that this would not obligate the Company to take this much to the shortlist, if there are clear separations among projects they may take less.