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May 30, 2008

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

Re: UM 1208 – Submission from the Oregon Independent Evaluators (Boston Pacific)

Dear Judge Grant:

On April 9, 2008, Staff filed a highly-confidential Non-Public document entitled "Final Closing Report on PacifiCorp's 2012 RFP" in PUC Docket UM 1208 on behalf of one of the Oregon Independent Evaluators (Boston Pacific). As noted in that filing letter, "Staff will file a non-confidential, redacted version of the Final Report in the near future following PacifiCorp's review of the document."

Enclosed is a redacted, non-confidential version of that report. Please note that I am serving this document on the other UM 1208 parties via email only.

Sincerely,

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

MTW:nal/GENY0064
Enclosures
C: All parties w/o enc.

FINAL CLOSING REPORT
ON PACIFICORP'S 2012 RFP

Presented to
The Oregon Public Utility Commission

By
Boston Pacific Company, Inc.

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April 8, 2008

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I. INTRODUCTION AND SUMMARY

This is Boston Pacific Company's Final Closing Report on the 2012 RFP. Boston Pacific, jointly with Accion Group, serves as the Oregon Independent Evaluator (Oregon IE). This report focuses on the development and evaluation of the final shortlist for the 2012 RFP. Accion Group is separately filing their Final Closing Report focusing on the Request for Qualifications (RFQ) process.

The primary purpose of this report is to provide to the Oregon Public Utility Commission (the "Commission") the Oregon IE's opinion on PacifiCorp's selection of a Final Shortlist in its 2012 Request for Proposal (2012 RFP). As will be explained in detail herein, the Oregon IE fully concurs with the top-tier Final Conditional Shortlist (herein called simply the Final Shortlist) chosen by PacifiCorp.[1] Note that this Shortlist was technically "Conditional" because there still remained issues to be resolved with the selected bidders before contract negotiations could begin in earnest. As explained later, the Oregon IE, with respect to one bid, does not fully agree with the Company's subsequent actions in negotiations with the shortlisted bidders.

The selection for the Final Shortlist is tied closely to the assumptions and the analytic methods used in PacifiCorp's 2004 Integrated Resource Plan (2004 IRP)[2] and

[1]The Oregon IE also was required to provide a report on the Initial Shortlist including a review of both price and non-price factors. Since, under the RFP rules, up to two times the utility's need may be passed through to consideration for the Final Shortlist all of the bids were deemed to make it through this screen., Thus, there is no Initial Shortlist Report *per se*. However, much of the required work was done and for detailed information on this phase of the evaluation please see our attached testimony to the Commission on November 2, 2007.

[2] PacifiCorp, *2004 Integrated Resource Plan* (January 20, 2005)

updated and refined in the 2007 IRP, issued just after this RFP[3]. In these IRPs PacifiCorp went through a process to select a Preferred Portfolio of resources to meet a forecast of its customer's future needs for electric capacity and energy.[4] A consistent three-step process is used to select the Final Shortlist.[5] First, PacifiCorp uses the Capacity Expansion Module (CEM) to define the lowest cost mix (the "optimal portfolio") of future resources under a range of assumptions about future market prices for fuel and electricity, carbon dioxide (CO_2) emission compliance costs, and required reserve margins. Second, it uses the Planning and Risk Model (PaR) to quantify the expected cost and risk of the various portfolios chosen with the CEM – each portfolio is evaluated under a varying range of assumptions for factors including, but not limited to, electric demand, outages and fuel price. Third, PacifiCorp uses the CEM once again to estimate the cost of the best portfolios from the PaR Model under a range of assumptions. In all these analyses, cost is defined as the present value of revenue requirements (PVRR) estimated to be paid by ratepayers over a 20-year forecast period.

As noted in the IRPs, the modeling process led to the selection of a Preferred Portfolio of resources. For purposes of the selection of the Final Shortlist, three major resources from that Preferred Portfolio are removed and the bids and benchmarks from the 2012 RFP compete to take their place. With this analysis, PacifiCorp selected a two-tier Final Shortlist. The top tier contains the [redacted] submitted in the 2012 RFP which have a [redacted] capacity of about [redacted] MW. These were found to be top-ranked because these bids were the most "robust" in the PaR analysis. That is, they were

[3] PacifiCorp, *2007 Integrated Resource Plan* (May 30, 2007)
[4] 2004 IRP, Section 5 and 2007 IRP Section 6
[5] PacifiCorp, *Request for Proposals: Base Load Resources* (April 5, 2007) pages 52 to 53

the bids which delivered the lowest risk-adjusted cost when tested across a wide range of assumptions; specifically, based on risk-adjusted PVRR (i.e. mean PVRR plus the product of the 95^{th} percentile PVRR and 5%) these [redacted] bids were in the portfolios ranked first and second in every scenario considered.

The key features of these [redacted] bids in the top-tier Final Shortlist, as well as the primary issues to be resolved, can be summarized as follows:

[redacted]

[redacted]

The Oregon IE concurs that these [redacted] bids should be in the top-tier Final Shortlist based on their robust results in the PaR Analysis. Robustness is the right criteria because it indicates that the chosen resources do best for consumers in the face of significant uncertainty about the future. No one can precisely predict key factors such as the path of natural gas prices or the level of CO_2-emission compliance costs. The CEM and PaR Analyses are the means by which PacifiCorp attempts to assure that the selected bids minimize long-term costs, while taking into account risks, as required by the Commission's Bid Guidelines.

PacifiCorp also chose for potential further consideration additional bids that, while not as robust as the bids in the top tier, still showed some measure of robustness. The [redacted] bids in PacifiCorp's bottom tier include: [redacted] The next steps with the bottom tier are not defined and there is no guarantee that negotiations will be conducted with these bidders. Neither has it been decided how the bottom-tier bids will be compared to new bids solicited through the new RFP to be issued by PacifiCorp in 2008. The Oregon IE concurs that [redacted] should be in the bottom tier, but would be reluctant to add [redacted] as according to our evaluation, it was consistently outperformed by [redacted]. Because the second-tier bids were merely "put aside" for potential future consideration we do not have a strenuous objection to the inclusion of [redacted] by PacifiCorp. Furthermore, the issue is basically moot as, according to the latest Company filings in the Commission's 2007 IRP docket, the Company is not interested in seeking [redacted] costs.

Since the 2007 IRP was issued almost concurrently with the RFP and since its methods are important to the selection of the Final Shortlist, the Commission's consideration of the IRP is important here. The Staff of the Public Utility Commission of Oregon (Commission Staff) has recommended that the Commission acknowledge the 2007 IRP with some important exceptions and modifications.[6] For purposes of the selection of the Final Shortlist, the more relevant of the Staff's expectations and modifications are those which question the viability of coal-fired resources. Three points are worthy of note in this context. First, PacifiCorp has stated that its three coal-fired benchmarks are no longer viable for 2012 and none of those three were considered for (or are in) the Final Shortlist. Second, [redacted] Third, as alluded to above, [redacted]

[6] Staff Report on item No. 1, Public Meeting Date: December 19, 2007, Oregon Public Utility Commission Docket No. UM 1208.

[redacted] PacifiCorp has proposed that a key topic for negotiation [redacted] Specifically, PacifiCorp has stated that "Coal resources will be required to indicate how they will indemnify the customers and shareholders for the CO_2 risk and cost greater than what the company would otherwise be exposed to with a gas resource."[7]

[7] Ibid, page 5

II. PROCESS HISTORY FOR THE 2012 RFP

Prior to PacifiCorp issuing its 2012 RFP, the Oregon IE had extensive discussions with the company about its RFP Design. Our assessment of RFP Design is in Attachment Four herein.

PacifiCorp issued its 2012 RFP on April 5, 2007. The RFP, which, as mentioned above, was driven by the Company's analysis for the 2004 IRP, sought up to 1,700 MW of base load resources for delivery in the 2012-2014 timeframe.[8] Bidders were given the option to bid a variety of technology types and transaction agreements, including: Power Purchase Agreements (PPAs), Tolling Agreements, Asset Purchase and Sale Agreements (APSAs) and Sales of Existing Facilities.[9]

Bidder's responses were provided to the Company on June 29, 2007. The RFP resulted in a total of [redacted] bids representing approximately [redacted] MW. The bids are listed below:

[redacted]

[8] PacifiCorp, *Request for Proposals: Base Load Resources* (April 5, 2007) pages 4 to 5
[9] Ibid., page 8

[redacted]

In addition to these bids, PacifiCorp put forth three benchmark proposals to be evaluated along with the bidders. The benchmarks were developed, as contemplated in the RFP, by the Company's Benchmark Team. Prior to turning the bids over to the Evaluation Team and prior to the review of the submitted bids, the IEs reviewed the cost inputs and assumptions used to create these company benchmarks. Since the typical concern about benchmarks is that they exclude and, thereby, understate total costs, the focus of our analysis was making sure that all cost categories were properly included in the reported cost of the benchmarks. We concluded that the benchmark costs were not understated and included all the major cost components that we would expect. A copy of our analysis is attached as Attachment Two. The Company Benchmarks were as follows:

- **IPP3 Benchmark:** A 340-MW share of the new coal-fired Intermountain Power Project Unit 3(IPP3) at the existing IPP site to be on-line in 2012.
- **Jim Bridger Benchmark:** A 527-MW share of the new coal-fired Bridger Unit 5 at the Company's Jim Bridger site to be on-line in 2014.
- **IGCC Benchmark:** A new 475-MW Integrated Gasification Combined Cycle (IGCC) facility at the existing Jim Bridger site to be on-line in 2014.

Throughout the month of July the Company held a series of phone calls with bidders with the goal of clarifying all of the salient points of the bids. In addition, calls were also held regarding bidder credit issues. The IEs monitored all of these calls to ensure that information was transferred correctly and that key points of contention were understood. On July 30th, [redacted] dropped out of the RFP, citing the slow process, security deposit requirements and better prospects elsewhere as reasons for its withdrawal.

At the beginning of August, the Company made the decision that its IPP3 benchmark was no longer a viable option going forward. On August 13th, after discussions with the IEs and Commission Staff concerning next steps, the Company issued a status memo. The memo discussed the non-viable nature of IPP3 and [redacted] and laid out options for moving forward, including cancelling the RFP or amending the RFP to include new gas-fired company benchmarks.

The Oregon IE disagreed with the Company's analysis in three substantive areas: (a) [redacted] (b) the impetus for the Company's actions, which the IE attributed primarily to the loss of IPP3, and (c) the options for moving forward. The IE listed several reasons why the loss of the IPP3 benchmark was not a substantive reason to cancel or amend the RFP and urged the Company to continue with the RFP evaluation process with the existing bids. Our reasoning was laid out in a memo to the Company dated August 15th, a copy of which is included in the Attachment One herein.

From August to October, no further attempts were made to resolve bidder qualification issues, conduct analyses, or move the RFP process forward. On October 2nd the Company filed a motion to amend the RFP in Utah.[10] Citing the non-viable nature of its IPP3 benchmark as well as "significant changes in circumstances" the Company requested a series of amendments to the RFP which would allow it to submit additional benchmarks, consisting of gas-fired combined-cycle units at the Company's Currant Creek and Lake Side locations. Under the proposed amendments bidders were also to be given the opportunity to refresh their bids and small changes were made to the RFQ process.

Later in the month, after additional protective measures were approved by the Utah Commission, the Company submitted a confidential supporting memorandum to support its action. The memorandum (a) pointed to the bidder deficiencies that the

[10] Rocky Mountain Power's Motion to Amend its 2012 Request for Proposals and Request for Expedited Treatment, Utah Public Service Commission Docket No. 05-035-47, October 2, 2007.

Company had laid out in its August status memo and (b) provided a comparison of the bids (but not the benchmarks) against PacifiCorp's forward price curve (a forecast of market prices). This comparison was identical to the price screen evaluation that was to be performed as part of the initial shortlist evaluation. PacifiCorp compared the costs of each bid to their projection of wholesale market prices for the same time period. [redacted] The full results of the comparison can be found in Attachment Six[11]. Note, again, that the results of this comparison were not used in the screening process as all bids were put through for consideration to the Final Shortlist.

On November 2nd, the Commission held a public meeting where the Company presented its case for amending the RFP. The Oregon IE also was present and provided its reasons as to why the RFP process should continue without amendment. In addition, the Oregon IE provided Commission Staff with written public comments as well as supporting memorandum in which confidential aspects of the case were discussed. Our written public comments, and the supporting memorandum are included in Attachment One herein.

[11] The numbers presented in Attachment Six were generated a few months after the confidential supporting memorandum and reflect updated bid inputs and assumptions

On November 28th, the Company submitted in Utah a notice of withdrawal of its motion to amend the RFP.[12] The Company, citing "overwhelming opposition" to its motion to amend, proposed to continue evaluating the current set of bids. In addition the Company: (a) declared that none of its benchmarks were viable going forward and (b) announced that it would be issuing a new RFP, on an expedited schedule, for additional capacity in the 2012 to 2017 timeframe.

Throughout December, the Company and both the Oregon and Utah IEs worked through the prescribed phases of the Final Shortlist analysis, described in more detail in the next section here. [redacted] On December 27th, after completion of the RFP analyses and consultation with the IEs, PacificCorp submitted to the Oregon and Utah IEs a document laying out the justification for the selection of the Final Conditional Shortlist.[13] The Oregon and Utah IEs indicated their concurrence with the top-tier Final Conditional Shortlist and the [redacted] top-tier bidders were notified of their selection to the Final Conditional Shortlist.

After notification PacifiCorp continued to work with the [redacted] shortlisted bidders to resolve remaining issues in order to proceed to final contract negotiations. [redacted]

[12] Notice of Withdrawal of Rocky Mountain Power's Motion to Amend its 2012 Request for Proposals, Utah Public Service Commission Docket No. 05-035-47, November 28, 2007

[13] See Attachment Three

[redacted]

[redacted]

III. OVERVIEW OF PACIFICORP'S METHODS AND ASSUMPTIONS FOR SELECTING THE FINAL SHORTLIST

As already noted, PacifiCorp's methods and assumptions for the selection of the final shortlist are closely tied to those in its IRP process. The 2012 RFP made it clear that, consistent with the modeling analysis used to determine the Preferred Portfolio in the 2004 IRP, a three-step process would be used to determine the Final Shortlist. Those three steps are defining portfolios, assessing stochastic risk, and assessing scenario risk.

A. DEFINING PORTFOLIOS

The Preferred Portfolio from the 2007 IRP is the starting point for the analysis leading to the selection of the Final Shortlist. PacifiCorp first removed three East Side resources from the Preferred Portfolio: (a) a 340-MW pulverized coal-fired resource in Utah set for operation in 2012; (b) a 548-MW gas-fired combined cycle plant in the East Side set for operation in 2012; and (c) a 527-MW pulverized coal-fired plant in Wyoming set for operation in 2014. PacifiCorp then allowed the [redacted] bids and three benchmarks to compete to replace the three resources that had been removed from the Preferred Portfolio. These [redacted] competing resources can be summarized as follows in Table One.

TABLE ONE

[redacted]

These [redacted] resources competed under twenty different sets of assumptions about the future – or twenty different "Cases." Each of the Cases was defined in terms of assumptions about planning reserve margin (12% or 15%), natural gas and electricity prices (low, medium, and high forecasts), coal prices (low and high), and CO_2 compliance costs (low (zero dollars), medium ($8 in 2008 dollars per ton) and high ($38) levels). Renewable resources were fixed in the form of 1,600 MW of wind-driven additions. Firm market purchases (also called Front Office Transactions) were allowed to compete with other resources up to levels indicated in the 2007 IRP. While the former assumption most likely does not reflect the actual renewable build going forward we think that, for the purposes of this analysis, these assumptions were fair. For each Case, the Capacity Expansion Model (CEM) was used to choose which mix (which "portfolio") of resources would result in the lowest cost for consumers; specifically, which portfolios had the lowest present value of revenue requirements (PVRR) over the 20-year forecast given the assumptions for each Case. Since PacifiCorp no longer considered its three coal-fired benchmarks to be viable, the CEM was run for an additional eight cases in which only the [redacted] third-party bids were allowed to compete. Thus, there were a total of 28 Cases run for the portfolio analysis. The selections in each of the original 20 cases are shown in Attachment Five.

Although the primary measure of robustness comes in the stochastic risk assessment in the next part of this section, it is also worth measuring robustness at this stage involving the selection of portfolios. That is, in what percentage of the original 20 cases is a particular bid or benchmark selected for the optimal portfolio? The higher the percentage, the more robust is that bid or benchmark. Table Two shows that [redacted]

TABLE TWO

ROBUSTNESS OF BIDS
AND BENCHMARKS IN
PORTFOLIO SELECTION

[redacted]

One additional point to draw out from the portfolio selection analysis is the clear importance of natural gas price assumptions to which resources are selected in the optimal portfolios. To draw this out, we will focus on the nine cases in which a 12% planning reserve margin was assumed and, then, natural gas prices, electricity prices, and the CO_2 compliance costs were varied.[14]

- With the *low* natural gas price/electricity price assumption, the same [redacted] resources are chosen for the optimal portfolio regardless of the level of CO_2 cost adder. The chosen resources are [redacted]

[14] See Attachment Five

- With the *medium* natural gas price/electricity price assumption, the first coal-fired resources make their way into the optimal portfolio. With the low or medium CO_2 cost adder, [redacted] of the [redacted] resources are coal-fired – these are PacifiCorp's two pulverized coal benchmarks (IPP3 Benchmark/Bid C and J. Bridger Benchmark/Bid F). With the high CO_2 compliance cost assumption, only one of the two coal-fired resources remains in the optimal portfolio (IPP3 Benchmark/Bid C).

- Finally, with the *high* natural gas price/electricity price assumption, [redacted] resources in the optimal portfolio are coal-fired and these same [redacted] are chosen regardless of the level of assumed CO_2 cost adder [redacted]

B. ASSESSING STOCHASTIC RISK

PacifiCorp then sent eleven unique Cases to be assessed for stochastic risk. The term *unique* means that the optimal portfolio in each of the eleven Cases is not duplicated in any other Case. The term *stochastic* refers to assumptions being randomly varied along a given distribution using a Monte Carlo method. Assumptions for five factors were tested. Those five assumptions were load (electric demand), natural gas commodity prices, wholesale electricity prices, hydro generation availability, and thermal generation availability.

The stochastic analysis was done with the Planning and Risk (PaR) Model. The assumptions were randomly varied to result in 100 model runs for each Case. This resulted in 100 different estimates of the cost – again, as measured by the PVRR over 20 years – for each of the eleven Cases. The average (mean) of these 100 estimates was provided as were various measures of the risk (or variation) in these 100 runs; these risk measures varied from (a) standard deviation to (b) the average of the highest 5% of the runs to (c) the cost for the Case at the 95th percentile. PacifiCorp chose to use as a measure of risk the cost for the Case at the 95th percentile and to weight that cost with the probability of occurrence – that is, to weight it by 5%. Adding the average cost for the Case to the probability-weighted 95th percentile cost yielded what PacifiCorp terms the *risk-adjusted PVRR*. There was extensive discussion of risk metrics among PacifiCorp and the IEs, and the Oregon IE agreed that this is one constructive measure of risk.

The stochastic risk assessment was conducted for each of four different assumptions about CO_2 compliance costs; the three scenarios mentioned above as well as a "high-plus" case of $61 per ton in 2008 dollars.. Each of the eleven Cases was ranked by risk-adjusted cost (PVRR) under each of the four CO_2 cost adder levels. The top rank (ranked first) was given to the Case with the lowest risk-adjusted PVRR.

The same Case (Case 7) was ranked first under each of the four CO_2 compliance cost assumptions. This Case included as its resources the [redacted]

[redacted]

The Case ranked second varied by CO_2 cost adder. For the *low* and *medium* CO_2 cost adder, the Case ranked second (Case 4) had [redacted] In addition, this Case also had [redacted] For the *high* and *high-plus* CO_2 cost adder, Case 2 ranked second. [redacted]

These risk-adjusted cost rankings across all four of the CO_2 compliance cost assumptions were the primary basis for judging the robustness of the top-tier Final Shortlist. Again, the [redacted] Bids in PacifiCorp's top-tier Final Shortlist appeared in the first-ranked Case every time, as well as being in the second-ranked Cases. Beyond these [redacted] Bids in the top tier, there were [redacted] resources present in the second-ranked Case portfolios – [redacted]

It also is worth noting the dollar value of the risk-adjusted cost (or PVRR) for these top-ranked Case portfolios. As can be seen in Table Three below, the risk-adjusted cost for the first- and second-ranked Case portfolios vary little within each of the CO_2

compliance cost assumptions; for the *low* CO_2 cost adder the range is \$21.021 billion to \$21.166 billion – less than a 1% difference.

TABLE THREE

RISK-ADJUSTED COST (PVRR) FOR THE
TOP TWO RANKED CASE PORTFOLIOS
(In billions of dollars of present value)

CO_2 COMPLIANCE COST ASSUMPTIONS

CASE NUMBER	LOW	MEDIUM	HIGH	HIGH-PLUS
Case 7	\$21.021	\$24.778	\$32.932	\$39.498
Case 4	\$21.166	\$24.935	-	-
Case 2	-	-	\$33.059	39.528

However, as can be seen in Table Three, the risk-adjusted cost varies significantly across the different assumptions about the CO_2 compliance costs. For example, looking at the top-ranked Case (Case 7), the risk-adjusted cost is \$21.021 billion when the CO_2 cost adder is zero, but it increases by 57% to \$32.932 billion with the high assumption for the CO_2 compliance costs (\$38 per ton). It should be noted that in each case these costs are for PacifiCorp's fleet as a whole plus the bids being evaluated in the case, not just the bids.

C. ASSESSING SCENARIO RISK

The third and final step in the selection of the Final Shortlist was to use the CEM to assess how the cost of the top-ranked Case portfolios from the stochastic risk assessment vary with different assumptions about fuel price, CO_2 compliance costs, etc.

Recall that, unlike the PaR model, the assumptions in the CEM model are defined outright, not varied along a distribution. Hence, these results each represent only one possible scenario. As explained above, all of the top-ranked Case portfolios included [redacted] PacifiCorp's top-tier Final Shortlist. In addition, each of the top-ranked Case portfolios PacifiCorp chose to evaluate in this third step included [redacted]

The costs for all three of these Cases were estimated with varied assumptions about coal prices, gas and electricity prices, and CO_2 compliance costs. The average cost for these three Cases across all the different scenarios were remarkably close. The average costs (average PVRRs) for Case 4, Case 2, and Case 9 were [redacted] respectively. In general, the portfolios were similar in each individual scenario as well, with the least expensive portfolio in a given scenario being what we would expect. For instance, for any emissions cost level, [redacted]

IV. ADDITIONAL RESPONSES TO ISSUES LISTED IN THE SCOPE OF WORK FOR THE OREGON IE

In Exhibit A of the Oregon IE's contract with PacifiCorp, a list of sixteen topics were required to be addressed in this Final Closing Report. We believe they have been addressed substantially in the preceding sections. For completeness, however, we list the sixteen here (by Roman numerals as in the contract) and provide a summary response to each.

i. **PacifiCorp's scoring of bids and Benchmark Resources**

ii. **The basis for ranking bids and Benchmark Resources**

iii. **The basis for selecting bids or Benchmark Resources**

iv. **The basis for rejecting bids or Benchmark Resources**

The methods by which the Company scored, ranked and accepted or rejected bids are documented more fully in Section III. The Company utilized the principle of "robustness" to rank and select among the bids. First, the Company developed a series of "optimal portfolios" of resources using the CEM model and varying gas prices, coal prices and emissions cost inputs. The portfolios were then placed into the PaR model where they were subject to a series of changes in gas prices, demand levels, power plant outages, hydro generation, wholesale prices and emissions costs. This resulted in 100 estimates of cost for each portfolio.

The top performing portfolios were selected on the basis of the risk-adjusted Present Value Revenue Requirement (PVRR), that is, the portfolios with the lowest risk-adjusted cost (PVRR) were ranked highest. We believe this ranking method to be an effective one because it incorporates uncertainty into future projections of multiple key variables and allows that uncertainty to inform the bid selection. The method does not take a specific view of the future, but rather analyzes which portfolio performs the best over many possible future outcomes, assuring that the selected portfolio is not "placing a bet" on any specific future outcome.

v. An analysis of whether the selected bids minimize long term costs, taking into account risks

The bids in the top tier were chosen because of their ability to minimize long term costs while including risk factors. This selection was achieved by looking for bids that performed well in the PaR analysis based on risk-adjusted PVRR. As explained in previous sections, risk-adjusted PVRR is the mean PVRR plus the product of the 95th percentile PVRR and the probability of that result occurring (i.e. 5%). The risk-adjusted PVRR was examined across four different CO_2 emission costs as well. In this manner, each portfolio of bids was tested for risks that included; gas prices, demand, wholesale prices, thermal outages, and hydro levels as well as emission costs. The bids in the top-tier Final Shortlist consistently were present in either the first or second highest performing portfolio based on risk-adjusted PVRR across all emission levels.

vi. **The Consultant's independent scoring of bids and Benchmark resources**

vii. **A comparison of the results of PacifiCorp's evaluation to the results obtained by the Consultant**

Our detailed review of the bid results is featured in Section III above. In answering this question it is important to lay out how the IEs independently evaluated the bids. In other solicitations a procurement monitor may construct a model in order to perform an evaluation of procurement results. In this solicitation, due to the complexity of the models required to evaluate the bids, the IEs did not construct such a model.

Despite this fact, the IEs conducted independent analysis in several ways: (i) by providing input and guidance into the RFP design via process participation and our RFP design report, (ii) by independently reviewing and evaluating the Benchmarks, (iii) by independently reviewing the modeling assumptions and methods, (iv) by participating in Company conversations with bidders to ensure that all bid inputs into the model were accurate and (v) by independently reviewing the outputs of each model run with the Company and checking those runs against the results we would expect based on the inputs.

As mentioned in detail in Section III above, we also utilized the principle of robustness to determine the top performing bids. We ranked bids based on risk-adjusted PVRR, looking for bids that delivered the lowest risk-adjusted costs. The Company followed the same method to rank its bids. We are in complete agreement with the Company as to the selection of the first tier of bids.

The only difference that we have with the Company in terms of results has to do with the second tier of resources. The Company wishes to include [redacted] as a bottom-tier Resource due to the fact that it was included in a top-five ranked portfolio in the low, high and high-plus emission cases. We are reluctant to include [redacted] because, based on risk-adjusted PVRR, the portfolio composed of the top-tier bids and [redacted] However, because the second-tier bids were [redacted] we do not have a strenuous objection to the Company's [redacted] Also, as noted, the Company has indicated that it will not consider coal-fired resources in the futures unless bidders can somehow indemnify the Company against future emissions compliance cost risks.

viii. A review of the fairness of the RFP

The Oregon IE believes that, in the end, the RFP process was fair. We discussed the issue or fairness and transparency at length in our assessment of PacifiCorp's RFP design which is attached. We noted that "Fair simply means that all bidders and benchmarks are treated comparably – the offers are evaluated in the same manner and all parties are asked to make the same guarantees to ratepayers on price and performance."[15] Also, we stated that "Transparency simply means that the methods of choosing who wins are clearly known and easily replicable."[16]

As described earlier herein, all bids and benchmarks were evaluated in the same manner with the CEM and PaR Model. Furthermore, in our assessment of the benchmark cost estimates, we concluded that PacifiCorp did not understate the costs of the three benchmarks (which is the typical concern). Finally, as was explained in our *RFP Assessment*, we did have some remaining concerns about the comparability of ratepayer risks from bids as opposed to benchmarks. For this RFP, those concerns became moot when PacifiCorp withdrew its benchmarks. .

With respect to transparency, the fact that the evaluation methods are so closely tied to the *2004 IRP* means that the public has been given an opportunity to judge the methods and assumptions to be used in the RFP. Confidentiality concerns justify limiting the distribution of all the detailed bid and benchmark review, but the fact that the Oregon IE was given full access to these documents provides substantial evidence of transparency.

One final comment on fairness is warranted. In our attached testimony, the Oregon IE stated that it would not have been fair to stop the 2012 RFP nor to amend the rules as proposed by PacifiCorp. Therefore, PacifiCorp's decision to proceed with the

[15] The Oregon Independent Evaluator's Assessment of PacifiCorp's 2012 RFP Design, page 4 (April 13, 2007) (hereafter *RFP Assessment)*
[16] Ibid.

existing 2012 RFP was welcome and added to our conclusion that, in the end, this was a fair process.

ix. The extent to which PacifiCorp evaluated the Benchmark Resources consistent with the Commission's Competitive Bidding Guidelines

While, in the end, the treatment of the Company's benchmark resources was a non-issue, as none of the benchmarks were deemed to be viable, we did have some issues with the Company's evaluation of the benchmarks during the process. Specifically, we objected to the fact that the benchmarks were not evaluated against the forward price curve along with the other bids. The Company only performed this analysis later for its confidential memorandum to support amending the RFP. Under the Commission's guidelines, scoring for benchmarks must be the same as for market bids. When this was pointed out to the Company, they stated that since the evaluation team was not supposed to view benchmark proposals, as per the RFP's Code of Conduct, there was no way that they could perform the analysis. As noted above, they later did in fact perform such a comparison. It is important to note that the Company appears to be altering its RFP process to accommodate Commission guidelines in the future. From our preliminary talks with the Company, it appears that bids in the upcoming 2008 RFP will be evaluated against the forward price curve along with other bids.

x. A discussion of whether PacifiCorp equitably and consistently applied screening factors and weighting to bids.

As we understand it, this issue concerned the screening and price/non-price weighting for the Initial Shortlist. It became moot when all bids were pushed through to evaluation for the Final Shortlist.

xi. A review of PacifiCorp's required credit and risk management terms and conditions, their application to bid evaluation and their impacts on the RFP outcome

Due to the current restrictive credit environment, credit requirements have an important effect on bidder participation. If requirements are overly restrictive, the effect can be to squeeze out otherwise viable competition. Likewise, bid conditions and restrictions that are developed to minimize risk to the Company can also reduce participation. These issues are certainly difficult to resolve since any RFP must walk the line between inviting as many bids as possible and making sure that ratepayers do not end up harmed by a bankrupt supplier or a problem bid.

Having said that, there were two particular areas regarding credit and risk management where we disagreed with the Company. First, regarding credit standards, PacifiCorp required that bidders produce a *letter of credit* along with their application. In other words, banks had to post credit guarantees even before the bids were assured of any spot on the initial or final shortlist. The result was a significant up-front cost to bidders. We believe that the problem of bid security could be better handled with a *letter of comfort*, which is less costly than a letter of credit, and a letter of credit required only after bids are selected to the final shortlist or at contract execution. The cost to bidders up front would be lower, and ratepayers would still receive protection for any bids that moved forward. For a more detailed evaluation, please see Accion Group's separate report, which focuses on the RFQ process.

Another area in which we disagreed with the company's risk management practices was in its allowance for only two indices (CPI and PPI) to incorporate inflation into a specified part of the bid. Bidders indicated that they had a difficult time locating and securing fixed-price guarantees from third-party vendors. [redacted] attempted to propose pricing that used a Treasury bill index as a marker for bid inflation. Despite the fact that the company requested "creative proposals" in the RFP, the Company refused to accept [redacted] We feel that, given the rapidly changing construction cost environment and the size of these financial commitments, the Company should accept and encourage these alternative pricing proposals, which could provide some benefits to ratepayers. We would recommend that for the upcoming 2008 RFP and other solicitations the Company solicit opinions from bidders concerning the current indexing framework and whether it is indeed possible to submit binding bids under this framework. If it is impossible then the Company should solicit ideas as to other ways in which proposals may include some form of cost control to protect ratepayers.

xii. The level of cooperation by PacifiCorp with the Consultant regarding access to information, personnel and models used in the evaluation of bids

PacifiCorp was cooperative with the IEs throughout the RFP process. The Company allowed for discussion and input from the IEs throughout the bid receipt and evaluation process on issues ranging from bidder qualification to bid evaluation to final shortlist selection. When specific issues came up, (e.g. transmission costs used in the analyses) the Company made appropriate personnel available to answer questions.

PacifiCorp provided access to its model analyses remotely through a secure website. Model results were also sent to the IEs via e-mail. Our only issue with the process was that the pricing input and transmission cost models that the Company used were only able to be viewed by the IEs and not altered and re-run. The Company offered the IEs the chance to use the models ourselves, but only at Company offices. We understand that there may be technical and proprietary reasons why the Company may want to keep the models at their offices, however, due to the size and complexity of the models, we would encourage the Company next time to attempt to arrange for the IEs to be able to remotely re-run the models. This "hands-on" process will allow the IEs to gain a better understanding and to become comfortable with how the models react to variations in inputs.

xiii. A discussion of public participation in the development and conduct of this RFP

The Oregon IE can speak to public participation only to the extent that it involved us. In the beginning of our role as the Oregon IE, we had two substantial meetings with stakeholders. The first was held in Portland on December 6, 2006; the key task at this meeting was to assure that the Oregon IE understood the full list of issues as seen by the stakeholders. The second meeting, also held in Portland, was on January 31, 2007; at this meeting, the Oregon IE laid out its preliminary thoughts on RFP design and received feedback from stakeholders.

We also attended the PacifiCorp Pre-Bid Meeting in Portland on April 25, 2007. While it did not involve interaction *per se*, the Oregon IE's *RFP Assessment* also counts in our view as an effort to communicate with stakeholders. We also put in this category our Testimony to the Commission on November 2, 2007 concerning PacifiCorp's proposed amendments to the 2012 RFP.

xiv. A review of the process by which issues were resolved and confidentiality was maintained

In order to determine the final shortlist, the Company held scheduled phone conversations with the IEs during which each side gave their opinion as to which bids should be moved on to the final shortlist and asked questions of each other to clarify opinions and analysis. This was generally the process followed by the Company and the IEs to handle issues throughout the RFP. Phone calls were held on: (i) bidder qualifications, (ii) final shortlist analysis, and (iii) RFP progress, among other issues.

As noted in Section II, the major exception to this dispute resolution process occurred when the Company filed its Motion to amend the RFP in Utah. While the Company did notify the IEs via a teleconference that they would be amending the RFPs, the filing of the Motion allowed for a more official comment process in Oregon and Utah. The IEs, as noted, presented public comments on the Motion as well as confidential supporting memoranda.[17]

During the process, a number of methods were used to maintain confidentiality. First, bids were blinded by the IEs before being sent to the evaluation team. Second, Company analyses were posted to a secured website that required a special passkey to enter. Third, the physical copies of bids sent to the IEs were sealed in secure locations. Fourth, key IE memos were sent out with password protection. Fifth, when the IEs presented public comments, the Company was able to pre-screen the comments in order to make sure that no confidential material was leaked.

xv. An overall assessment of PacifiCorp's compliance with the Commission's guidelines and regulations governing this RFP

The Oregon IE discussed the RFP's compliance with the relevant Bidding Guidelines in its *RFP Assessment* and that discussion is still relevant. However, suffice it to say that the process complied with all the Guidelines that were applicable, save one.

[17] Comments of the Oregon Independent Evaluators, Oregon Public Utility Commission Docket No. UM 1208, October 29, 2007.

The one for which there was not compliance, at least in part, was Guideline 8, which requires the benchmarks to be evaluated and scored *prior to the opening of the bids*. The benchmarks were reviewed by the Oregon IE prior to the opening of the bids but they were not scored for the Initial Shortlist prior to opening the bids.

The issue came to light when PacifiCorp, as part of its filing in support of its proposed amendments to the 2012 RFP, compared all bids to the Company's forward price curve (its forecast of market prices), but did not do the same for benchmarks. As mentioned above, this comparison was later provided for the record. For the upcoming 2008 RFP we understand that the Company's self-build options will be screened, along with all other bids, against the forward price curve as part of the initial shortlist screening.

xvi. To the extent that a conflict of interest is identified, the Closing Report will discuss the nature and consequence of such conflict

To our knowledge, there were no conflicts of interest that arose during the RFP. The Company did, to our knowledge, operate according to its Code of Conduct, and thus maintained a separation between the teams that created the Benchmark proposals and the evaluation team.

ATTACHMENT ONE
COMMENTS OF THE OREGON INDEPENDENT EVALUATORS IN DOCKET UM-1208 (WITH CONFIDENTIAL ATTACHMENTS) (NOVEMBER 2, 2007)

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UM 1208

In the Matter of PacifiCorp's Draft 2012 Request for Proposals	§ § §	**Comments of the Oregon Independent Evaluators**

INTRODUCTION

1. Boston Pacific and Accion Group jointly serve as the Oregon Independent Evaluators (IEs) for PacifiCorp's 2012 Request for Proposals (2012 RFP). The IEs are represented today by Craig R. Roach, Ph.D., President of Boston Pacific Company, Inc. [1] (Boston Pacific), and Harold Judd, Vice President of Accion Group (Accion)[2].

2. On September 28, 2007, PacifiCorp filed with the Utah Public Service Commission (Utah Commission) the first of three documents in which it requested approval to amend and delay the 2012 RFP[3]; this first document asked that the Utah Commission approve an amendment to the Protective Order that would limit the range of persons able to review select subsequent confidential filings. On October 2, 2007, PacifiCorp filed the second document in which it described the amendment for which it sought approval and implied some of the justification for the proposed amendment.[4] On October 17, 2007, PacifiCorp provided to the Oregon IEs the third document[5]; this document purports to offer the full justification for the proposed amendment and request for delay and it was marked as highly sensitive non-public information.

3. In its Amendment filing to the Utah Commission, PacifiCorp summarizes its proposed amendment and request for delay as follows:

> The Company's motion requests Commission authorization to amend the 2012 request for proposals with respect to the following: (1) to modify the schedule in Section 2, whereby the proposal response date would change from June 19, 2007 to January 18, 2008, permitting new and existing bidders an opportunity to submit new bids or refresh their existing bids; (2) to eliminate the upfront request for qualifications procedure and

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[1] Boston Pacific's business address is 1100 New York Avenue NW, Suite 490 East, Washington, DC 20005.

[2] Accion's business address is 244 North Main Street, *The Carriage House*, Concord, NH 03301.

[3] *Rocky Mountain Power's Motion for Additional Protective Measures and Request for Expedited Treatment*, Docket No. 05-035-47, hereafter "Protective Order filing." A similar filing was made in Oregon on October 23, *Docket No. UM 1208, In the Matter of PacifiCorp's Draft 2012 Request for Proposals PacifiCorp's Motion for Additional Protection.*

[4] *Rocky Mountain Power's Motion to Amend its 2012 Request for Proposals and Request for Expedited Treatment*, Docket No. 05-037-47, hereafter "Amendment filing."

[5] Memorandum in Support of Rocky Mountain Power's Motion to Amend its 2012 Request for Proposals, Docket No. 05-035-47, hereafter "Supporting Memorandum."

instead, require submission of an intent to bid form; to modify the qualification requirements so that new bidders will be required to submit qualification appendices with their bids and existing bidders will only need to update qualification appendices if information has changed; and to only require bidders (new and existing) to post acceptable commitment letters or letters of credit within ten business days following notification of their selection to the initial shortlist; and (3) to update the 2012 benchmark resources by including resources located at the existing Lake Side site and/or existing Currant Creek site.

4. **The bottom line of our comments today is that the Oregon IEs oppose PacifiCorp's proposed amendment and request for delay. Our opposition reflects our view that the proposal is unnecessary, unfair to existing bidders, and potentially harmful to ratepayers in both the near- and long-term.**

5. Attached to these public comments is a document which explains in more detail our reasons for opposing the PacifiCorp proposal. It is marked Non-Public Information Subject to Special Protective Order because it relies on protected materials. We will note, however, that a key part of the confidential attachment is a memo Boston Pacific wrote to PacifiCorp, copying Oregon Staff, Utah Staff, and the Utah IE, on August 15, 2007, soon after PacifiCorp first proposed the idea of amending and delaying the 2012 RFP. In that August 15 memo we stated our opposition and the reasons for our position are mostly, if not entirely, identical to those we present today.

PACIFICORP'S 2012 BENCHMARK RESOURCE

6. Let us turn in more detail now to the reasons for the Oregon IE's opposition. In its public filings to the Utah Commission PacifiCorp refers to "certain events" or "significant change in circumstances" which led it to its motion to amend and request to delay the 2012 RFP.[6] In our view, there is a single event which primarily motivates the PacifiCorp proposals: it is PacifiCorp's doubts about the viability of its 2012 benchmark resource which was based on a 340 MW share of the proposed Intermountain Power Project Unit 3 (IPP3).

7. In our view, PacifiCorp's doubts about the IPP3 benchmark resource are not sufficient justification for the proposed amendment and delay of the 2012 RFP. Most important, by no means does PacifiCorp's loss of its IPP3 benchmark resource mean there are no benchmarks for the RFP.[7]

[6] Protective Order filing at 2 and Amendment filing at 3.

[7] The Commission defines a Benchmark as follows in Order No. 06-446 at 5: "We define a Benchmark Resource as a site-specific, self-build option for which there is a commitment to proceed if it is the resource selected through the RFP. This definition does not preclude a utility from designating the market as an alternative comparator during the RFP evaluation process. If no resources are acquired through the RFP because bids are inferior to the evaluation benchmark, we do not expect an emergency selfbuild shortly thereafter."

a. IPP3 was considered to be a viable benchmark at the time the bids were submitted and, in this sense, it did its job – it established a price threshold to be used in evaluating bids, and thereby, it put pressure on bidders to offer to ratepayers the lowest price, lowest risk, highest reliability, and best environmental performance possible. Indeed, if the bids are reopened (as PacifiCorp proposes) we might expect less attractive offers now that PacifiCorp has so widely publicized its doubts about the viability of IPP3.

b. The existing IPP3 benchmark resource may still be used as a point of comparison against other bids for evaluation purposes. We should get the results of that comparison and see how it affects the choice of winning bids before we take additional action.

c. In addition, even if IPP3 is put aside, PacifiCorp has two other benchmark resources that it continues to see as viable: (a) a share of a conventional coal fired unit at the existing Jim Bridger site in Wyoming for 527 MW and (b) a 500 MW integrated gasification combined cycle (IGCC) unit at the same site.[8] PacifiCorp should compare the submitted bids to these two benchmark resources. One way to accomplish this would be by "bridging" the benchmarks, which have on-line dates in 2014, with a forecast of short-term power supply purchases in 2012 and 2013.

d. And, finally, another point of comparison on price – another benchmark of sorts – is the estimate of market prices (the "forward price curve") that PacifiCorp's RFP states will be used for its bid evaluation for the Initial Shortlist. To be of value here, the forward curve would have to be used to assess both third-party bids and benchmark resources.

8. As to PacifiCorp developing a new benchmark resource based on gas-fired combined cycle plants, without real bid analysis there simply is no need to amend and delay the 2012 RFP so PacifiCorp can go off and develop new benchmark resources for 2012.

9. To our knowledge, the decision to amend and delay was based on the fact that PacifiCorp doubts the viability of its IPP3 benchmark, not on any substantive analysis of the prices bid as compared to any of the benchmark resources.

FLEXIBILITY ON BIDDER QUALIFICATIONS

10. PacifiCorp does propose a constructive action which we fully support in concept, though we believe PacifiCorp's proposal is unnecessarily restrictive. PacifiCorp should be more flexible on the qualification requirements for bidders until the point in time that a bidder knows it has been short-listed and is to be engaged in negotiations for a Power Purchase Agreement (PPA) or another agreement. The most important area in need of some flexibility is credit requirements.

[8] 2012 RFP at Attachment 1.

11. To be more flexible on credit requirements, PacifiCorp proposes that Bank (or other credit support) Commitment Letters and Guarantees be required only after a bidder is chosen for the Initial Shortlist, rather than at the time the bid is submitted. (Actual Letters of Credit and Guarantees are required upon selection as a provider of power.) We believe even more flexibility would be well advised. For example, Letters of Comfort, an early indication of a bank's interest in committing, could be required from bidders at the time the bidder is advised that PacifiCorp wants to start negotiation of PPA terms. Bidders should be advised that once on the Initial Shortlist they will be required to identify credit source and provide Letters of Commitment contemporaneously with the execution of a power purchase or other contract. Actual Letters of Credit would be required only upon Utah Commission approval of the arrangements negotiated.

12. Whatever the flexibility offered, the key point is that PacifiCorp does not have to amend and delay the 2012 RFP to allow this flexibility. We believe PacifiCorp has the ability to allow such flexibility within the rules of the existing RFP.

THE POOL OF EXISTING BIDDERS

13. PacifiCorp states that, by amending and delaying the 2012 RFP it would get a more robust pool of bidders.[9] This statement gives an unfortunate and inaccurate picture of the robustness of the existing pool of bidders. It is our view that the concern implied here by PacifiCorp would be addressed by flexibility on bidder credit and other non-price qualifications and, as already stated, we believe PacifiCorp has the discretion to be flexible in these ways.

14. Moreover, the amendments and delay could have the exact opposite effect – they could decrease the number and quality of bidders as well as the aggressiveness of their offers. Bidders could drop out because of the delay. Bidders could drop out because they believe the PacifiCorp proposal undermines the credibility of the RFP process.

15. With respect to credibility, PacifiCorp states that, with its proposal, it is providing equal treatment to all bidders.[10] But bidders would be forgiven if they doubt that, if a bidder's proposal was in danger like IPP3, PacifiCorp would have afforded the bidder the same opportunity to stop the entire process until that bidder could pull together another bid with an entirely new technology.

16. Further in this regard, we would not blame a bidder for taking a darker view of PacifiCorp's purpose. In that darker view, bidders might be concerned that after PacifiCorp sees the true viability of its IPP3 bid, it changes its mind about betting on coal plants and now gets a chance to re-bid with gas-fired plants at Currant Creek and

[9] Amendment filing at 5 "...the Company is hoping to yield a more robust pool of bidders..."
[10] Id., "...all parties are treated equally and given a fair opportunity to participate..."

Lakeside. And PacifiCorp gets that chance regardless of how many other gas-fired plants have already been bid. Similarly, a bidder might wonder why, with viable benchmarks at the Jim Bridger site in 2014, PacifiCorp does not use these benchmarks – and fill in with purchases for 2012 and 2013 – to compare to all existing bids. In short, a bidder might believe PacifiCorp is angling to assure that it "wins" the RFP. It is actions like this by PacifiCorp that undermine credibility.

17. And undermining the credibility of the RFP could have harmful effects well beyond the 2012 RFP. It could undermine future RFPs.

18. As we understand it, the policy of the Public Utility Commission of Oregon (as well as the Utah Commission) is to vet the addition of Major Resources through a competitive process to assure ratepayers get the best deal in terms of price, risk, reliability and environmental performance. With such a policy, driving away bidders by undermining the credibility of the RFP is the last thing that PacifiCorp should be allowed to do. Put simply, you cannot have competition without competitors.

INFORMING THE IRP WITH THE RFP

19. The Commission hoped that the 2012 RFP would inform, and thereby, "improve upon" PacifiCorp's IRP.[11] PacifiCorp's eagerness to embrace more flexible gas-fired resources might be an example of what the Commission had in mind. However, the full and fair analysis of the existing bids is more likely to achieve the Commission's competitive bidding goals.

ALTERNATIVE APPROACH

20. For the reasons stated above, we suggest an alternative approach in which PacifiCorp stays the course with the existing 2012 RFP and abandons the attempt to amend and delay it. Specifically, PacifiCorp should freeze the evaluation of credit and all other non-price requirements, and move forward with the full price evaluation of all existing bids. Full price evaluation would include all three benchmarks: (a) all bids and all three Benchmark Resources should be compared to the Forward Curve developed for the Initial Shortlist and (b) all bids and all three Benchmark Resources should be evaluated through the modeling process developed for the Final Shortlist. PacifiCorp would then know the bidders offering the best price deal for ratepayers. If those bidders beat the benchmark resources, PacifiCorp would then finalize on all price and non-price factors with the best bidders and execute contracts.

[11] Order No. 07-018 at 7.

MEMORANDUM

October 29, 2007

TO: Chairman Lee Beyer
Commissioner Ray Baum
Commissioner John Savage

CC: Lisa Schwartz, Public Utility Commission of Oregon Staff

FROM: Boston Pacific Company and Accion Group, Oregon Independent Evaluators

SUBJECT: Confidential Attachment to the Oregon Independent Evaluators' Comments for the November 2, 2007, Special Public Meeting (Docket UM 1208)

INTRODUCTION

The purpose of this memo is to: (a) introduce the attached, confidential Status Memo which Boston Pacific drafted and sent to PacifiCorp in August; (b) emphasize certain items in the memo in light of PacifiCorp's actions over the past two months; and (c) provide confidential evidence which supports our public comments.

The attached Status Memo represents our interpretation of where the RFP process stood as of August 15th of this year. It outlines our interpretation of the status of each bid, potential paths forward, and our objections to PacifiCorp's proposal to amend and delay the 2012 RFP. We present it here as an attachment because it is still very informative; little has changed since it was written. The following section discusses issues which we would like to draw out, given recent events.

STATUS MEMO AND KEY ISSUES

PacifiCorp's Actions Over the Past Two Months

All of the bidder deficiencies that PacifiCorp cites in its recent filing were known two months ago. In the Status Memo, we pointed out two potential options for moving forward: (a) freezing the non-price qualification process and analyzing the prices of [redacted] or (b) analyzing the prices of the [redacted]

[redacted] Our objections to PacifiCorp developing a new benchmark resource were laid out as well.

In the past two months, PacifiCorp, despite its stated concerns with the bidder pool, has done nothing to remedy any of the deficiencies noted. Since the Status Memo was written, no bidders have been contacted regarding these deficiencies. In fact it was not until October 17th that the bidders were informed of the Company's decision to amend and delay the RFP. During that time, no analyses have been provided to the Oregon IE regarding the price and non-price competitiveness of the bids as compared to PacifiCorp's benchmark resources and no further progress has been made in resolving the outstanding Request for Qualifications (RFQ) issues identified in PacifiCorp's recent filing in Utah.

Additionally, the one constructive change PacifiCorp proposes – the change to credit requirements – would have little, if any, effect on the existing pool of bidders. [redacted] Simply moving the credit requirements to a slightly later stage, as PacifiCorp proposes, would not resolve these issues. Nor do we believe these changes are likely to attract many new bidders; they are not fundamental changes in the qualification requirements and may cause bidders to doubt the credibility of the process.

With respect to credibility, we note that one of the new gas-fired benchmark resources that PacifiCorp proposes[1] [redacted]

[redacted]

[1] The company proposes to add gas-fired, combined-cycle 2012 benchmark resources at its Lake Side and Currant Creek sites.

[redacted]

In sum: (a) in more than two months the Company has taken no action to move the existing RFP forward, and (b) the proposals PacifiCorp makes are unlikely to remedy bidder deficiencies or elicit a substantial number of new bids. This supports our view that the primary motivation for amending and delaying the RFP is to give PacifiCorp time to develop new gas-fired benchmarks to replace its failing IPP3 project. [redacted]

The Robustness of the Pool of Bids

Currently [redacted]

As outlined in the Status Memo, [redacted]

While we do not want to excuse unresponsiveness on the part of the bidders, it seems to us that the wise course here would be to continue with the full price evaluation process as originally envisioned in the RFP. By doing this we would know which bidders will need to cure non-price issue deficiencies and whether the Company may have to compromise on selected non-price concerns in order to secure low-cost and reliable power. Once this price analysis is completed and reviewed, an final "short-list" can be established and bidders on that list can cure or negotiate resolution of any critical bid deficiencies.

PacifiCorp's Forward Price Curve

In our August 15th Status Memo, we asked that PacifiCorp conduct the RFP-mandated comparison of the bids to the forward price curve (PacifiCorp's market price forecast). In its confidential supporting memorandum, PacifiCorp provides such a comparison. However, we have several issues with the analysis provided:

- First, we were not given the opportunity to view, assess, or test the analysis prior to the Company's filing in Utah. In fact, we only received access to the models on October 23rd.
- Second, the Company states [redacted]
- Third, the Company did not test the benchmarks against the forward curve, so there is no reason to draw the conclusion that the existing benchmarks or any more benchmarks will necessarily beat the forward curve.

Allowing the RFP to Improve Upon the Company's Resource Plan

One of the Commission's goals was to have the RFP inform, and thereby, improve upon the company's resource plan[3]. The Commission hoped that the RFP process would be a way to vet various assumptions concerning future energy markets. Staying the course with the existing RFP will do just that in the following ways:

- First, it will test [redacted]
- Second, through the failure of PacifiCorp's IPP3 benchmark and evaluation of the other bids, staying the course will help inform the choice between gas- and coal-fired generation.
- Third, analysis using PacifiCorp's forward curve will test the assumption of using market purchases as a "bridge" to a future date when technology changes have helped to lower generation costs.

[2] Supporting Memorandum at page 5.
[3] OPUC Docket No. UM-1285, Order No. 07-018 at page 7.

We do not know the final answers to these questions, but by completing the RFP process *as is* we will be able to draw out and be better informed in order to advise the Commission on these crucial issues.

MEMORANDUM

August 15, 2007

TO: Stacey Kusters
PacifiCorp

FROM: Craig Roach
Frank Mossburg

SUBJECT: Response to PacifiCorp August 13th Status Memo

The purpose of this memo is to respond to the Status Memo on the 2012 RFP sent by PacifiCorp on August 13th to the Staff of the Utah Division of Public Utilities and the Oregon Public Utility Commission. While we appreciate the effort, our conclusion is that the memo does not reflect a complete view of where the RFP process stands or the options for going forward. Specifically, it: a) fails to mention another option that Boston Pacific proposed in writing for going forward, b) fails to note how [redacted] and c) fails to explain how the cancellation of PacifiCorp's Intermountain Power Project Unit 3 (IPP3) project could justify the cancellation or splitting of the RFP.

OPTIONS FOR GOING FORWARD

The Status Memo provides for five options going forward and our understanding of each is as follows:

1. Split the RFP into two RFPs, one for 2014 and one for 2012-2013. For the first RFP *current* bidders would be given the option to offer power to be on-line in 2014. These offers would compete with the existing Bridger 5 Benchmark. For the second RFP, reopen the 2012-2013 period to *new* bidders, while adding new company Benchmarks at Lake Side and/or Currant Creek.

2. Freeze the eligibility process of the RFP and perform an initial price evaluation on [redacted]

3. Freeze the eligibility process of the RFP, allow current bidders to offer power on-line in 2014, and perform an analysis for 2014 power only.

4. Move forward with all current bidders and do not require eligibility or credit screens to be met [redacted]

5. Cancel the RFP and issue two new RFPs, one for 2012-2013 and one for 2014, with new company Benchmarks for 2012-2013 as in (1) above.

There is another option that we have discussed with the Company and it was not included in this list. That option is to go forward with the RFP process, as designed, by evaluating [redacted]

The Company would perform the initial shortlist analysis as proposed to assess whether there are cost savings for ratepayers from these bids as compared to market prices. Then, assuming the bids brought cost savings for the ratepayers, the Company would declare these bids the winners and go forward and negotiate final contracts with [redacted]

It is our understanding that PacifiCorp believes this option would be addressed under Option (2) above, (the "freeze and evaluate" option). This is not the case. First, to be clear about the "freeze and evaluate" option, it was our intent when Boston Pacific proposed Option (2) that the credit and eligibility section of the RFP process be simply "frozen" for a time while all of the bids were evaluated on the merits of their proposal. When the bids that achieve the greatest cost savings have been identified, we would then "unfreeze" the credit and requirements section to finish collecting all the necessary data for those bids. The advantage of this suggestion is that it would allow us to figure out which bids were worth our efforts going forward as we attempt to collect all of the requirements pieces. It would also allow us to better understand which issues we might have to be more accommodating on, rather than deciding that at the outset.

Second, this added option that we are proposing is different in that it *continues with the RFP process as scheduled for* [redacted] There is no need for a "freeze" on [redacted] The advantages of this option are: a) it allows all parties to say that they followed the RFP process as written and that all bids were treated equally and fairly, b) bids would still be screened against replacement power costs to ensure cost savings for ratepayers and c) it allows for up to [redacted]

CURRENT STATUS OF BIDS

We understand that this new option may not be ideal in that it allows a full price evaluation of [redacted] That is why we think it is very important to note another fact not included in the Status Memo. The fact is that there are [redacted]

[redacted]

[redacted]

RFP CANCELLATION DUE TO PROBLEMS WITH A BENCHMARK

Of the five options proposed by PacifiCorp above, Options (1), (3), and (5) involve either the cancellation of the RFP or splitting of the RFP into a 2012-

13 and/or 2014 phase. We think that it is important to note that the motivation for all of these options is that PacifiCorp no longer believes the IPP3 Benchmark is a viable project for 2012; the apparent concern is the LADWP objection to building IPP3. We do not believe that PacifiCorp's problems with IPP3 justify cancellation or amendment of the RFP.

We have five reasons as to why the RFP should not be split or cancelled due to the failure of the IPP3 Benchmark.

- First, while there will be no IPP3 Benchmark going forward, there was an IPP3 Benchmark *when the bids were submitted;* therefore, each bidder had to price their product with the knowledge that it would face IPP3 Benchmark competition. That competitive effect took place even though we now know IPP3 is not viable.

- Second, there still remains a viable benchmark in the form of PacifiCorp's expected replacement power prices that will be used to evaluate the bids going forward. These prices are viable benchmarks because they reflect PacifiCorp's forecast of what ratepayers will actually pay if nothing is built by 2012.

- Third, allowing PacifiCorp to submit new Benchmark Bids due to the failure of the IPP3 project would be unfair to the bidders who have participated in the process so far. We doubt that, if this were a bidder proposal in danger, the bidder would be afforded the same opportunity to submit another bid. This is particularly true when we consider the fact that the LADWP opposition was known prior to PacifiCorp choosing its IPP3 Benchmark.

- Fourth, even if a new RFP was issued, the fact it is coming so soon after this one makes it highly unlikely that new bidders will emerge.

- Fifth and finally, even if the RFP were split, [redacted]

Taken in total these five reasons show that PacifiCorp's problems with IPP3 are not justification as we see it for canceling the RFP or splitting the RFP in two. If we remove the options that are motivated by the IPP3 failure we are left with the following choices:

1. Freeze and Evaluate: Freeze review of the credit and eligibility requirements and move forward with the price evaluation of all current bids, returning to complete those reviews when we know which bids are the best deals for customers. (Option (2) in PacifiCorp's memo and as originally proposed by Boston Pacific)

2. Continue with [redacted] whether cost savings can be achieved for ratepayers as compared to purchases at market prices. If cost savings exist, negotiate and sign final contracts with [redacted]

3. Competitive Negotiation: Agree to deem as eligible all bidders, move on to the price evaluation, and enter competitive negotiations (Option (4) in PacifiCorp's memo as originally proposed by the Utah IE.)

We would be happy to discuss this memo as well as any other issues that parties might have. We suggest setting up a call between PacifiCorp, the Utah and Oregon IEs and the Staffs for both Commissions to discuss next steps. Thank you.

CC: Lisa Schwartz
Tom Brill
Artie Powell
Natalie Hocken
Dean Brockbank
Jim Schroeder
Wayne Oliver
Ed Selgrade
Harry Judd
Alan Kessler

Pacificorp
Request for Proposals
Base Load Resources
[redacted]

October 5, 2007

Utah Independent Evaluator
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Salt Lake City, Utah 84114-6751

Oregon Independent Evaluator
Accion Group and Boston Pacific Company, Inc.
c/o Pacific Power Legal Department
Attention: Natalie L. Hocken
825 NE Multnomah, Suite 200
Portland, OR 97232

RE: PacifiCorp Request for Proposals
Base Load Resources
[redacted]

Dear IE's:

[redacted]

Pacificorp
Request for Proposals
Base Load Resources

[redacted]

[redacted]

[redacted]

ATTACHMENT TWO
ANALYSIS OF THE PACIFICORP BENCHMARK BIDS (JULY 2, 2007)

MEMORANDUM

July 2, 2007

TO: Lisa Schwartz
Maury Galbraith
Oregon PUC

FROM: Craig Roach
Frank Mossburg
Andy Ludwig

SUBJECT: Analysis of the PacifiCorp Benchmark Bids

BACKGROUND AND SUMMARY

Background

As you know, the Independent Evaluator for the Oregon Public Utility Commission, Boston Pacific (along with Accion), has been tasked with preparing an evaluation of the Benchmark resources, including verifying that the "assumptions, inputs, outputs and results are appropriate and reasonable."[1] The purpose of this memo is to document our findings with respect to our review of PacifiCorp's Benchmark proposals for the 2012 Request for Proposal for Base Load Resources (the "2012 RFP).

PacifiCorp's offered Benchmark resources are as follows:: 1) a 340-MW share of Intermountain Power Project Unit 3 (IPP3), a new 900-MW Supercritical Pulverized Coal (SCPC) facility to be added to the existing IPP plant in Utah in 2012, 2) a 527-MW share of the Jim Bridger Unit 5 SCPC facility, a proposed 790 MW addition to the existing Jim Bridger facility in Wyoming scheduled for 2014 and 3) the Jim Bridger Integrated Gasification Combined Cycle (IGCC) facility, a new 475 MW facility to be constructed on the existing Jim Bridger site, also in 2014. PacifiCorp would own 37.8% of IPP3, 66.7% of the Bridger coal unit and 100% of the IGCC facility.

In Boston Pacific's experience, the typical danger with utility Benchmark proposals such as these is that they omit many capital costs that should otherwise be included so as to make their bid artificially low and not reflective of what the ratepayers will actually be paying -- that is, costs estimates are often "lowballed.". With that in mind, we focused our investigation by creating a list of costs that are

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[1] PacifiCorp RFP for Base Load Resources, Attachment 4.

typically omitted from these types of submissions. We then conducted a thorough examination of PacifiCorp's submissions and detailed supporting documentation, including the company's backup cost sheets, which contained the detailed line item inputs that were rolled up into the total capital cost estimates. We also conducted lengthy discussions with PacifiCorp staff, in order to determine whether or not PacifiCorp had, in fact, included these costs in their estimates. We also compared the capital costs of the Benchmarks to some of the few publicly available cost estimates for comparable power plants to try and get another take on the overall reasonableness of PacifiCorp's cost estimates and performance.

Summary

[redacted]

[redacted]

BOSTON PACIFIC'S ACTIONS TO REVIEW AND VALIDATE THE BENCHMARKS

Boston Pacific relied on a multi-part investigation in order to review and validate the Benchmark submissions. First, we attended a pre-submission meeting in Salt Lake City, Utah where company officials presented an overview of each facility, including such information as design data, fuel inputs, cost sources, and other inputs. Second, we reviewed the full contents of each submission made by PacifiCorp. Third, we participated in phone calls with the Benchmark design team in which we were able to ask clarifying questions. Fourth, we reviewed the detailed cost breakdown sheets, hereafter referred to as the "Backup sheets" which the company used to create the Benchmark cost inputs. These sheets showed line item details on included costs and showed how those costs were rolled up into the cost estimates which were then used on the Pricing Input Sheet. Finally, we reviewed publicly available cost information for other, similar facilities to get a sense as to the accuracy of the costs.

ASSESSMENT OF THE BENCHMARKS

[redacted]

[redacted]

[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

ATTACHMENT THREE
PACIFICORP'S FINAL CONDITIONAL SHORT LIST DEVELOPMENT FOR THE BASE LOAD REQUEST FOR PROPOSALS DOCUMENT
(DECEMBER 27, 2007)

Final Conditional Short List Development for the Base Load Request for Proposals

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

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[redacted]

[redacted]

ATTACHMENT FOUR
THE OREGON INDEPENDENT EVALUATOR'S ASSESSMENT OF PACIFICORP'S 2012 RFP DESIGN (APRIL 13, 2007)

THE OREGON INDEPENDENT EVALUATOR'S ASSESSMENT OF PACIFICORP'S 2012 RFP DESIGN

PART ONE: EVALUATION CRITERIA, METHODS AND COMPUTER MODELS

PART TWO: ADEQUACY, ACCURACY AND COMPLETENESS OF SOLICITATION MATERIALS

PART ONE

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April 13, 2007

TABLE OF CONTENTS

I. INTRODUCTION, BACKGROUND AND SUMMARY

A. INTRODUCTION

Accion Group Inc. and Boston Pacific Company, Inc. were selected through a competitive solicitation by the Public Utility Commission of Oregon (the "Commission") to serve as the Independent Evaluator (Oregon IE) for PacifiCorp's 2012 Request for Proposals (2012 RFP).[1] On January 25, 2007, Accion and Boston Pacific executed a contract with PacifiCorp to serve as the Oregon IE. Under the terms of that contract, the Oregon IE is required to prepare the *IE Assessment of RFP Design*. This report is meant to satisfy that requirement. The scope of the IE Assessment is defined by the Commission as follows:

> The assessment should take into account the Commission's goals (page 2 of the order) and the three criteria for RFP approval (Guideline 7) and specifically address Guidelines 6, 7, 8, 9, 10, 11 and 13, as well as issues raised by parties in UM 1208. The assessment should address the *evaluation criteria, methods and computer models* as well as the pro forma contracts included with the RFP. The assessment also should review *the adequacy, accuracy and completeness of all solicitation materials* to ensure compliance with the Commission's competitive bidding order and consistency with accepted industry standards and practices. [Emphasis added][2]

The purpose of this initial assessment is to identify areas of concern regarding the RFP design and to recommend areas where PacifiCorp could improve the RFP. In conducting this initial assessment we reviewed the RFP processes affecting the ability of bidders to participate, the evaluation tools, models, techniques and assumptions to be used, and the Pro Forma Agreements prepared by PacifiCorp which will be the basis on which transactions will be finalized.

In reviewing the PacifiCorp RFP design and materials, we drew upon our experience as Independent Evaluators and Independent Monitors in other solicitations. Our assessment is guided in part by the Competitive Bidding Guidelines developed by the

[1] Order No. 06-676 (Entered 12-20-06).

[2] The Commission's Request for Proposals #07-PSK-1004 at page 7. The "order" referred to is the Commission's order on competitive bidding, Order No. 06-446 (entered August 10, 2006).

Commission, its Competitive Bidding Goals, and by the criteria for a fair and transparent RFP adopted by the Federal Energy Regulatory Commission (FERC). We believe the Commissions Guidelines, coupled with the FERC standards, to be thorough and well articulated. Accordingly, in making our overall assessment of the RFP design, we sought to determine whether:

- the RFP complies with the Commissions Guidelines
- the process is designed to be open and fair, permitting all bidders access to the same information at the same time;
- prospective bidders and other Stakeholders were provided with draft RFP documents and the opportunity to request or recommend changes to those documents;
- the IE was provided open access to PacifiCorp personnel and evaluation modeling information, upon request;
- the IE was engaged before the RFP was completed and released to bidders in final form, and provided sufficient time to review the RFP documents and processes;
- the RFP documents provide clear and complete product definition;
- the RFP documents provided full disclosure of the evaluation process that would be employed;
- the Company would appropriately and equitably evaluate all bids;
- the Company's proposed evaluation process adequately assesses the risks associated with various bids; and,
- as designed, the RFP process calls for all bids to be evaluated using the same standards and evaluation models and methodology.

With this scope, Accion and Boston Pacific agreed to an efficient delineation of responsibility. Boston Pacific is responsible for assessing "evaluation criteria, methods and computer models," including Guidelines relevant to that topic. Part 1 of this report presents Boston Pacific's assessment. Accion is responsible for assessing "the adequacy, accuracy and completeness of all solicitation materials," including the pro-forma contracts and, again, the Guidelines relevant to that topic; Part 2 of this report presents Accion's assessment.

The last draft of the 2012 RFP filed in Oregon was dated November 1, 2006. For that reason, this report assesses both the November 1, 2006 draft and the RFP approved by the Utah Public Service Commission. We have previously provided to Commission Staff, PacifiCorp, and Stakeholders in several forums, our comments on the 2012 RFP draft submitted to the Oregon Commission on November 1, 2006. However, Commission Staff and PacifiCorp asked us to delay submitting this Report so that the final RFP presented in Utah would be the basis of this IE Assessment. Thus, this Assessment reflects all changes made to the 2012 RFP submitted to the Utah Commission on March 22, 2007. We also reviewed the reports submitted by the Utah IE to better understand the evolution of the RFP and the changes to the RFP process that PacifiCorp had incorporated.

B. BACKGROUND

In the scope defined for an IE Assessment the Commission refers to its "goals," "three criteria for RFP Approval," and to "Guidelines 6, 7, 8, 9, 10, 11 and 13." All of these are contained in the Commission's Order on competitive bidding guidelines; this is Order No. 06-446 dated August 10, 2006.

- The five goals as stated by the Commission are: "Provide the opportunity to minimize long-term energy costs, subject to economic, legal and institutional constraints; complement Oregon's integrated resource planning process; not unduly constrain utility management's prerogative to acquire new resources; be flexible, allowing the contracting parties to negotiate mutually beneficial exchange agreements; and be understandable and fair."[3]

- The three criteria for RFP approval, as stated by the Commission are: "The alignment of the utility's RFP with its acknowledged IRP; whether the RFP satisfies the Commission's competitive bidding guidelines; and the overall fairness of the utility's proposed bidding process."[4]

- The seven guidelines cited by the Commission can be summarized as follows:
  (a) Guideline 6 addresses RFP design, specifically the process and content of the draft RFP; (b) Guideline 7 addresses RFP Approval, specifically the three criteria quoted above; (c) Guideline 8 addresses Benchmark Resource Score; (d) Guideline 9 addresses Bid Scoring and Evaluation Criteria, specifically the determination of the Initial and Final Shortlists plus the imputed debt issue; (e) Guideline 10 addresses Utility and IE Roles in the process; (f) Guideline 11 addresses the IE Closing Report; and (g) Guideline 13 addresses RFP acknowledgment.

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[3] Order at page 2.
[4] Order at page 9.

Importantly, on January 16, 2007, the Commission denied PacifiCorp's request for approval of its 2012 RFP. Under Guideline 7, the Commission found that the 2012 RFP "is not aligned with the company's acknowledged integrated resource plan (IRP)."[5] The Commission also raised concern as to the satisfaction of other Guidelines and focused the IE on a prospective judgment on fairness.

C. SUMMARY OF PART ONE

Consistent with the Commission's stated goals, the purpose of bid evaluation should be to get the best possible deal for ratepayers in terms of price, risk, reliability, and environmental performance, given current market and regulatory conditions. This is best achieved by conducting a RFP which is fair and transparent. Fair simply means that all bidders and benchmarks are treated comparably – the offers are evaluated in the same manner and all parties are asked to make the same guarantees to ratepayers on price and performance. Transparency simply means that the methods of choosing who wins are clearly known and easily replicable. Assessing the RFP is just one step in judging fairness and transparency. PacifiCorp's 2012 RFP cannot be finally judged to be fair and transparent until the process – most notably the bid evaluation process – is completed.

Based on our experience across the country, Boston Pacific has developed a list of key issues that must be addressed when designing a competitive solicitation to assure the best chance of getting the best deal for ratepayers, and, to that end, to assure fairness and transparency.[6] All of these key issues are encountered in the 2012 RFP. PacifiCorp addresses some of these issues quite constructively, while, for others, additional effort is needed to address them in full. Our views can be summarized as follows:

1. <u>PacifiCorp does not fully account for differences in ratepayer risks across transaction types. This creates a potential bias toward the benchmarks that would invalidate the process.</u>

Because of the great uncertainty about market and regulatory conditions in the future, assessment of ratepayer risk is the most challenging task in finding the best deal for

[5] Order No. 07-018 at page 1.
[6] Boston Pacific Company, Inc. <u>Getting the Best Deal for Electric Utility Customers.</u> EPSA: Washington, D.C., 2004.

ratepayers. The risks assigned to ratepayers differ widely across the transaction types solicited in the 2012 RFP. The largest potential difference is between (a) the lower ratepayer risk with a bid for a pay-for-performance power purchase agreement (PPA) and (b) the higher ratepayer risk with a benchmark offering cost-plus rates.

The price and performance guarantees with the PPA are of value to ratepayers and ratepayers would readily understand that a higher price for power might come along with a lower risk PPA; just as they understand that a fixed-interest rate mortgage has a higher interest rate because it offers guarantees not available with an adjustable rate mortgage. The obvious difference in risk must be taken into account to assure a fair (apples-to-apples) evaluation of offers. If not, there is a potential bias in favor of the benchmarks. PacifiCorp could resolve this issue through two alternatives. One is to quantify the difference in risk and use adders/subtractors to account for it. The second is to hold all bids and benchmarks to the same risk standard – that is, hold the benchmarks to the same guarantees made to ratepayers in a pay-for-performance PPA.[7] We consistently recommend the second approach.

An announcement that PacifiCorp is willing to be held to its benchmark cost and performance estimates makes the RFP more credible to bidders and should entice more aggressive bidding. Absent such an announcement, bidders may believe PacifiCorp has both the opportunity and incentive to understate costs and overstate performance for its benchmarks.

It is our understanding that PacifiCorp has agreed that its benchmark will be held to its "capacity cost payment." PacifiCorp will be allowed to index its capital costs in the same way bidders can.[8] This is a good step towards addressing our concerns about the comparability of risk for cost-plus benchmarks and pay-for-performance bids. However, PacifiCorp has not agreed to be held to the other components of its benchmark estimates, such as capital additions and fuel cost, and this remains a concern for us.

[7] As explained later, another approach would be to have PacifiCorp's estimates of Benchmark cost and performance serve as standards of prudence.
[8] At the request of the Utah Commission, PacifiCorp will allow bidders to index up to 40% of capital costs. Up to 25% may be indexed to the Consumers Price Index and 15% to the Producer Price Index for Metals and Metal Products. *See* 2012 RFP at page 40.

2. PacifiCorp has a credible approach to assessing differences in ratepayer risks across technology types. However, it should add at least one more risk to its assessment.

PacifiCorp plans to use the same measures of risk-reward trade off that it uses in its IRP analysis. This is a credible analytical approach. We understand that capital cost risk will be assessed and that the risk is comparably bounded for all bids and benchmarks by the allowed indexing. (The allowed indexing for capital cost states that up to 40% may be indexed, with 25% indexed to the Consumer Price Index (CPI) and 15% to the Producer Price Index for metals and metal products.) In addition, coal price risk (not just natural gas price risk) will be assessed. These are both good steps forward by PacifiCorp. It is still a bit unclear whether bids and benchmarks without performance (availability) guarantees will have availability risk evaluated; such an evaluation should be included. Also, we recommend that the risk of selling surplus power for alternative portfolios should be drawn out (the extent, value, and nature of power sales for each portfolio).

3. PacifiCorp has a sound approach to the assessment of CO_2 regulatory risk. The Company also has stated a policy that limits the ratepayer risk for the pass through of CO_2 compliance costs.

The potential for CO_2 regulation has increased notably in just the last two or three years. PacifiCorp has proposed to assess this risk through a scenario analysis using a range of assumed CO_2 taxes. Based on our review of recent studies and legislation, the range PacifiCorp has used in previous IRPs appears to be appropriate in the sense that the lower end of the range ($8/ton of CO_2) reflects less aggressive legislation while the higher end ($25 to $40/ton of CO_2) is aligned with more aggressive legislation. We believe PacifiCorp will use this same range here, but PacifiCorp has not made this clear in writing.

Further, it is our understanding that the CO_2 regulation risk analysis will include the assessment of a range of portfolios, not just a preferred portfolio.[9] We recommend that the analysis be done to reveal the "tipping points" – that is, at what level of CO_2 tax would the preference tip to a portfolio with natural gas from one with coal, from a portfolio with conventional coal to IGCC, etc.

[9] 2012 RFP at page 53.

Finally, PacifiCorp has stated a contractual limit on the nature and extent of the ratepayer risk for the pass through for CO_2 compliance costs. Specifically, PacifiCorp stated that any pass through of CO_2 compliance costs would be subject to review and approval by the Utah Commission.[10] This provides basic protections to ratepayers, but we would have preferred more details on the policy standard for pass through.

4. <u>PacifiCorp should take additional steps to assure that the option value of shorter-term offers to ratepayers is fully recognized. This is to avoid a bias for longer-term offers.</u>

Shorter-term offers can give ratepayers option value in the sense that, if market or regulatory conditions change significantly in the future, PacifiCorp can move from these contracts (when they expire) to options better suited to the changed circumstances. To assure this option value is assessed, it is important that there is no bias against shorter-term offers in either the Initial or Final Shortlist.

We understand that an annuity method is used for the Initial Shortlist so the concern would be allayed there. For the Final Shortlist, however, a "fill-in" method is used to account for differences in term length. That is, all offers will be evaluated for 20 years and, if an offer was made for say 10 years, the remaining 10 years would be filled in with an assumed replacement source of power. PacifiCorp uses two reasonable assumptions for replacement power: (a) spot market purchases and (b) a new generic power plant such as a combined cycle plant. However, both of these have the downside of, in effect, assuming this winning bidder goes away – it is not available to bid and win again in a future RFP.

To address this downside, we suggest using one or two other assumptions to reveal any possible bias against short-term offers. Both of the two we suggest have the appeal of letting the original offer, "speak for itself." One is simply to take the original offer and escalate it for cumulative inflation as appropriate. The second is to assume the bidder would offer a price in the same proportion to market prices in the future as it did when it won the original RFP – we understand that the Commission Staff asked Portland General Electric to

[10] 2012 RFP at pages 56 and 57.

test an additional scenario like this in its 2003 RFP.[11] These two added analytic assumptions would be used as sensitivity analysis to see if the nature of the preferred portfolio would change.

5. PacifiCorp has now clarified the responsibility of bidders for transmission interconnection and transmission system integration costs.

PacifiCorp requires that all power plants offered be network resources. To achieve network status, transmission interconnection costs and transmission system integration costs must be estimated. PacifiCorp must do this estimation in a comparable manner for both bids and benchmarks. That comparability will be crucial for the evaluation process to be judged to be fair and it will be something that requires vigilance by the Oregon IE at that time.

PacifiCorp has clarified what must be included in the bid price. For *interconnection* costs, the bidder must reflect all of the cost in its offer price.[12] In contrast, PacifiCorp directs bidders to exclude transmission system *integration* costs from their bid prices. However, PacifiCorp will include estimates of integration costs for both bids and benchmarks in its evaluation.[13]

6. To its credit, PacifiCorp will not include "imputed debt" in bid and benchmark evaluation.

The "imputed debt" issue has caused considerable controversy in other RFP evaluations. PacifiCorp has constructively avoided the issue for its 2012 RFP by stating that it will not include imputed debt in either the Initial or Final Shortlist. (For this reason, there is no additional discussion herein.)

7. Again, to its credit, PacifiCorp has not included a regulatory-out clause in its transaction contracts. This will mitigate regulatory risk for bidders and, thereby, encourage aggressive (lower price) bids. However, added steps are necessary to address the Commission's remaining strategic concerns.

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[11] Public Utilities Commission of Oregon Docket No. LC 33. Portland General Electric : Final Action Plan Acknowledgement. 5/19/04. p. 18.
[12] 2012 RFP at pages 43 and 44.
[13] Ibid., at page 44.

Some bidders may be concerned with regulatory risk in a multi-state environment. Differences in the level and nature of acknowledged resource needs across the states could drive this. PacifiCorp has not included a regulatory-out clause in its transaction contracts. This is a direct, constructive way to mitigate this concern for bidders.

Still, in the context of regulatory uncertainty, PacifiCorp should design the RFP to address strategic issues remaining for the Oregon Commission: (a) baseload versus seasonal peak need; (b) the risk and benefit of "bridging" strategies for IGCC; and (c) the need to re-assess a full range of technologies including renewables, demand-side measures, etc.

The Commission is especially concerned whether IGCC bids are accommodated. Such accommodations include the fact that IGCC is in its own category for the Initial Shortlist; the top bids in each category make this shortlist. Another accommodation is that IGCC bids may be in any of three transaction types – PPA, tolling, or asset sale. Further, performing the full CO_2 regulatory analysis should allow IGCC to demonstrate any advantages in this regard. In addition, at the pre-bid meeting, PacifiCorp should also make it clear that an IGCC bid (or any technology type) with an on-line date beyond 2014 is acceptable if the cost of power supply until the specified on-line date is borne by the bidder.

Finally, because the addition of new resources becomes most visible to ratepayers through impacts on monthly bills, we suggest the impact on future rates (as compared to current rates) be assessed as the Final Shortlist is determined. This, too, will help to manage regulatory risk.

8. <u>Some of the concerns stated above in items 1 to 7, mean that PacifiCorp could do more to satisfy the Commission's competitive bidding guidelines.</u>

Guideline 8 would be better satisfied if PacifiCorp, as discussed above, takes steps to account for the higher ratepayer risk of cost-plus regulatory treatment of some of the costs for the benchmarks.

Guideline 9a is better satisfied now that PacifiCorp explicitly seeks diversity across fuel types in its Initial Shortlist. However, it must also assure, as discussed above, that the option value of shorter-term offers is fully assessed.

Guideline 10d would be better satisfied if PacifiCorp takes additional steps to address the Commission's remaining strategic issues.

D. SUMMARY OF PART TWO

ADEQUACY, ACCURACY AND COMPLETENESS OF ALL SOLICITATION MATERIALS

In general, we found that the RFP documentation approved by the Oregon Commission is reasonably clear and consistent with standard industry practice. We also found that the revised RFP documents clarified several points and incorporated several of the matters raised by the Oregon IE during our discussions with the Company. Among these are the ability of Bidders to toll transportation of fuels and significant clarification of the requirements imposed on bidders of IGCC projects. Both the draft documents and the final RFP have been reviewed, The Final RFP, as approved by the Utah Commission, it's associated Agreements, and attachments can, in our opinion, serve as the basis for a fair and transparent RFP if the RFP is implemented as described in the documentation. The Company has adequately described the Benchmark Resources it intends to use to evaluate against all bids and each of the power supply products for which it will accept bids. The IE does however still have certain concerns regarding the RFP documentation that is addressed below.

1.) <u>The RFP adequately describes the products sought.</u>

We take as a given that various stakeholders have questioned the appropriateness of the products being solicited, and the Commission has found that the RFP is not aligned with the Company's most recently acknowledged IRP in terms of the level and nature of need. Many of these concerns are addressed in the following sections. However, on a more basic level, the products sought by PacifiCorp are adequately described in the sense that bidders will understand that PacifiCorp is seeking unit contingent or firm baseload resources.

2.) <u>PacifiCorp should solicit for seasonal and peaking resources for terms of 5 years or more.</u>

As discussed further, later in this Report, we believe that, in light of the Commission's finding that this RFP is not aligned with PacifiCorp's IRP, PacifiCorp should expand it's product requests and definitions to incorporate a request to acquire seasonal and peaking resources for terms of five or more years to address the concerns raised by the Commission in regard to PacifiCorp's need for base load resources. PacifiCorp did not in its Final RFP accept this recommendation.

3.) <u>The Draft RFP did not explicitly disclose that PacifiCorp would not seek a "Regulatory-Out Clause".</u>

We believe that, in light of the Commission's rejection of PacifiCorp's filed Draft RFP and PacifiCorp's decision to not re-file an amended Draft RFP, the RFP document should specifically disclose in the RFP that PacifiCorp will not seek to negotiate a "Regulatory Out Clause" in any Agreement entered into in this RFP.

To its credit, PacifiCorp has made the requested disclosure in its revised Utah filing.

4.) <u>PacifiCorp's Code of Conduct is comprehensive and appropriate for purposes of conducting this RFP.</u>

While PacifiCorp has made reasonable efforts to prevent even an inadvertent disclosure of RFP-related information, except through the RFP protocols, we will continue to closely monitor communications between the Company and Bidders to assure that information is provided in an unbiased and timely manner.

5.) <u>The Bidder qualifications and Credit requirements are reasonable.</u>

We found that the RFP establishes both Bidder Qualification Requirements and Credit and Security Requirements that are within the norms of industry practice.

6.) <u>PacifiCorp's initial draft did not permit Bidders to request the Tolling of fuel transportation. As recommended by the Oregon IE, its Final RFP permits Bidders to propose tolling of natural gas transportation.</u>

The Company has indicated that it will accept bids for tolling arrangements for both natural gas and coal fired resources. Initially, these arrangements were for fuel only. We recommended that PacifiCorp allow bidders to submit bids seeking transportation tolling and should evaluate whether such proposals can reasonably be managed and provide an economic benefit. PacifiCorp has amended its RFP to permit Bidders to propose tolling gas transportation.

7.) The initial drafts did not clearly describe the responsibilities of Bidders proposing to utilize IGCC technology regarding the provision of service in the event that the facility proposed would not be available in 2012. In the approved RFP the Company attempted to clarify this point.

We believe that the Company intends to treat IGCC bids in the same manner as it will treat all other bids and should therefore further clarify this point during its meetings with potential Bidders and via an announcement on both its website and on the website maintained by the Utah IE.

Taking the above recommendations and the actions taken by PacifiCorp to incorporate several of these recommendations into the RFP, we believe that the RFP documentation and related materials proposed by the Company are adequately structured to conduct this RFP. As noted, we have concerns regarding, among other things, PacifiCorp's unwillingness to consider accepting bids for seasonal or peaking power supply products. Although the documentation is adequately structured, only after PacifiCorp conducts this RFP and evaluates the bids it receives will we be able to assess whether the RFP process as implemented, was fair and equitable. Similarly, only after PacifiCorp selects its preferred portfolio of winning bids will we be able to evaluate whether it solicited for and selected products that were appropriate for its customers needs and satisfied the Oregon Commission's Competitive Bidding Goals. As required by the Commission, we will, as part of our responsibilities, review the actual application of the design as the final RFP documents are released and bids are received and evaluated.

PART ONE: EVALUATION CRITERIA, METHODS AND COMPUTER MODELS

II. TO ASSURE THE BEST DEAL FOR RATEPAYERS, THE METHODS FOR BID AND BENCHMARK EVALUATION MUST BE FAIR AND TRANSPARENT

A. WHY FAIRNESS AND TRANSPARENCY MATTER

Consistent with the Commission's stated goals and guidelines for competitive bidding, 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. To achieve that purpose, again, consistent with the Commission's policies, the methods of bid and benchmark evaluation must be fair and transparent to all. Only if this is the case will a large number of competing power suppliers participate and bid aggressively, convinced that the solicitation is an honest opportunity. And, in the end, only if there is a large number of bidders and aggressive bidding will ratepayers be convinced that they actually got the best deal possible.

The Federal Energy Regulatory Commission (FERC) also emphasized fairness and transparency in an important Order[14] in 2004 in which it set out the standards for competitive solicitations that would be used to justify a utility's long-term purchase of power from an affiliate. When setting the standards, the FERC stated:

> The fundamental objective of the solicitation guidelines is that the affiliate should have no undue advantage over non-affiliates in the solicitation process. Adhering to the guidelines will ensure that wholesale customers receive the benefit of the marketplace, including an unbiased assessment of the full range of choices, whether the soliciting utility provides service at cost- or market-based rates.
>
> The solicitation guidelines have four principles:
>
> a. Transparency: The competitive solicitation process should be open and fair.
> b. Definition: The product or products sought through the competitive solicitation should be precisely defined.
> c. Evaluation: Evaluation criteria should be standardized and applied equally to all bids and bidders.
> d. Oversight: An independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection.[15]

[14] 108 FERC ¶61,081 (Opinion No. 473 dated July 29, 2004).
[15] 108 FERC ¶61,081 (Opinion No. 473 dated July 29, 2004) at page 25 ¶69 and 70.

The Oregon Commission also emphasized fairness and transparency in 2006 when setting guidelines for competitive bidding.[16] Two of the five goals that the Commission confirmed for competitive bidding are worth noting in this regard. The first goal expresses the need to get the best deal for ratepayers – "Provide the opportunity to minimize long-term energy costs, subject to economic, legal, and institutional constraints."[17] The fifth and last goal simply states that the solicitation should be "understandable and fair"; words which we see as the equivalent of fair and transparent.[18]

In the thirteen specific guidelines the Commission sets, it promotes fairness and transparency at several other points. Guideline 5 requires the use of an Independent Evaluator (IE) "to help ensure that all offers are treated fairly."[19] Guideline 6 requires an open process in which the utility's RFP design is vetted in "bidder and stakeholder workshops" and also requires the RFP be vetted in a Commission proceeding.[20] Guideline 7 sets three standards for the Commission's review of the RFP design and one of the three is "overall fairness of the utility's proposed bidding process."[21] Guideline 8 requires that the "score should be assigned to the Benchmark Resource using the same bid scoring and evaluation criteria that will be used to score the market bids."[22]

B. HOW TO ACHIEVE FAIRNESS AND TRANSPARENCY

There is no single right way to solicit power and, therefore, there is no single right way to achieve fairness and transparency. To some observers, the ideal in fairness and transparency is a competitive solicitation in which all parties bid (including the local utilities) under identical terms and conditions and the bid evaluation is done solely on price – we term this a "price-only" bid evaluation. (It was a case involving a price-only solicitation in which the FERC set its four principles quoted above.) For a price-only bid evaluation, the product being solicited must be precisely defined and all the non-price factors must be standardized. We would put into this category the descending clock auctions in New Jersey

[16] Order No. 06-446.
[17] Order No. 06-446, at page 2.
[18] Ibid., at page 2.
[19] Ibid., at page 6.
[20] Ibid., at page 7.
[21] Ibid., at page 9.
[22] Ibid., at page 10.

(now in its sixth year) and in Illinois (the first was conducted in 2006). We also would put in this category the standard offer service (SOS) RFPs in Maryland (2006 is the fourth year), in the District of Columbia (in its third year) in Delaware (in its second year).

The product for these auctions is precisely defined. The product is full requirements power supply which, in essence, makes each supplier responsible for serving a percentage share of the needs of a ratepayer class whatever that share turns out to be in terms of capacity, energy, and ancillary services. In this way, suppliers take on market risk. Moreover, the supplier offers to serve at a fixed price and, in this way, takes on many other market and regulatory risks. Each winning bidder provides a financial guarantee that it will live up to its requirement to serve at a fixed price; if the supplier fails to provide the service, and a higher price is incurred to do so, the supplier has provided financial collateral which will be called upon to pay the increase in price.

Two further points should be made on what we have termed price-only auctions and RFPs. First, all of these are held in parts of the country in which there are regional transmission organizations (RTOs) or independent system operators (ISOs). The RTOs and ISOs provide two crucial accommodations: (a) a liquid energy spot market in which suppliers can buy and sell power as needed and (b) an independently run transmission system. Second, these auctions and RFPs generally solicit contract lengths no longer than three years.

These price-only solicitations are not without their critics. For example, some argue that the contract lengths and some other standardized terms are not sufficient to justify new capacity additions, especially those (a) with long lead times, (b) that are capital intensive, and (c) that are new (not fully commercialized). Others point to the fact that the solicitations have sometimes resulted in significant rate shock because they have been used to move to market prices after long periods of rate freeze. Still, these price-only solicitations have substantial merit and score especially well on fairness and transparency.

We are by no means suggesting that PacifiCorp must conduct a price-only type of solicitation. Our intent is simply to provide a point of comparison. RFPs designed like PacifiCorp's 2012 RFP surely can be fair and transparent, but it takes vigilance in the implementation, especially in bid and benchmark evaluation. Based on our experience across the country, Boston Pacific has developed a list of issues that must be addressed when designing and implementing such a competitive solicitation to assure the best chance of getting the best deal for ratepayers, and, to that end, to assure fairness and transparency. All of these key issues are encountered in the 2012 RFP. PacifiCorp addresses some of these issues quite constructively, while, for others, additional effort is needed to address them in full. Our views are summarized in the remaining sections of Part I of this report.

III. EVALUATION METHODS MUST ACCOUNT FOR DIFFERENCES IN RATEPAYER RISK ACROSS TRANSACTION TYPES

A. DEFINING THE ISSUE

If the future price, reliability, and environmental performance of each alternative benchmark or bid were known with certainty, bid and benchmark evaluation would be much easier. The evaluator could easily determine the alternatives with the lowest price, highest reliability, and best environmental performance. The remaining, difficult task would be to make tradeoffs (if any) between price and reliability, price and environmental performance, and reliability and environmental performance.

In reality, there are no facts about the future, so risk is pervasive and it makes the evaluation process much more complex. The evaluation process should focus squarely on ratepayer risk since we are attempting to find the best deal for ratepayers. Ratepayer risk is the risk that the actual price, reliability, or environmental performance is different from that which is projected for the future and used to determine the winners in the evaluation of benchmarks and bids.

There is no way to completely eliminate risk because there is no way to eliminate uncertainty about the future need for electricity or the best ways to fill that need. The RFP must do two things to take account of inevitable risk. First, the evaluation methods must incorporate risk. Second, risk must be assigned to the party in the best position to mitigate it. This assignment of risk is done through transaction contracts.

B. PACIFICORP'S APPROACH

PacifiCorp has sophisticated tools that provide quantitative measures of risks faced by ratepayers. This is PacifiCorp's approach to incorporating risk into the evaluation and the approach has considerable merit. We address those tools later in Section IV of this report. What we are addressing in this Section is not the measurement of risk, but, rather, the assignment of risk through the various transaction types.

PacifiCorp allows (indeed it invites) a very wide range or transaction types, including power purchase agreements (PPAs), tolling agreements, and asset sales. By casting its net broadly, PacifiCorp allows "the market to speak" in the sense that it allows bidders to state a preference for transaction type. The concern is that this makes the evaluation process complex because ratepayer risk varies greatly across the invited transaction types.

PacifiCorp originally called for traditional cost-plus ratemaking for all the costs of its benchmarks. With cost-plus ratemaking, all risks are assigned to ratepayers before the fact; that is before the investment is actually made. However, a risk can be shifted to PacifiCorp after the fact through a prudence review. In this sense, we should say that, under cost-plus ratemaking for the Benchmark Resources, all risk is assigned to Oregon ratepayers within the bounds of prudence. This is in sharp contrast to the substantial before-the-fact assignment of risks to bidders achieved through transaction contracts such as a pay-for-performance PPA.

The Commission must have understood that ratepayers face different risks under cost-plus ratemaking and PPAs. In Bidding Guideline 4, the Commission clearly allowed utilities to "use a self-build option in an RFP to provide a potential cost-based alternative for customers."[23] The Benchmark Resources are self-build options. While the Commission clearly allowed cost-plus options, it just as clearly required that the risk of such cost-plus options be assessed. The Commission stated in Guideline 10.d. "the IE will evaluate the unique risks and advantages associated with the Benchmark Resource (if used), including the regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected for the RFP."[24]

[23] Order 06-446 at page 5.
[24] Order 06-446 Guideline 4 at page 12.

With respect to the Commission's directive in 10d, PacifiCorp appears to delegate that task to the Oregon IE. PacifiCorp states:

> Oregon Order No. 06-446, Guideline 10(d), requires that the Oregon IE evaluate the unique risks and advantages associated with the Benchmark Resources, including the regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected for the RFP.[25]

As to the benchmarks, it is our understanding that PacifiCorp will be held to the "capacity cost payment" used for evaluation. However, this is not confirmed in the RFP. Indeed, PacifiCorp states bluntly that its benchmark is not a bid:

> It should be noted that the Benchmark Resources are not considered bids. While the intent is to evaluate the Benchmark Resources and the bids received from Bidders on a comparable basis, the Company does intend for the Benchmark Resources to be treated like market bids for purposes of subsequent ratemaking treatment.[26]

All other cost components for the benchmark, however, will receive cost-plus regulatory treatment. Furthermore, PacifiCorp makes no mention of accounting for differences in ratepayer risks for the other transaction types.

C. IE DISCUSSION OF THE ISSUE

One of the most important innovations of competitive reform, in general, and competitive bidding, in particular, is that risks have been increasingly assigned before the fact to power suppliers; that risk allocation to power suppliers is most often achieved through a pay-for-performance PPA. Not only does this take risk off the shoulders of the ratepayer, but it also helps to minimize risk because it assigns risk to a party that is in a position to do something about it – that is, to mitigate that risk. This assignment of risks through a PPA to parties in a position to mitigate risk is greatly advanced as a power supplier then re-allocates risks through its subcontracts for engineering, procurement, and construction (EPC), project finance, operation and maintenance (O&M), and fuel supply.

[25] 2012 RFP at page 55.
[26] 2012 RFP at page 6.

Lower risk to ratepayers due to risk assignment can be a major benefit of competitive bidding. But the risk mitigation or risk management inherent in before-the-fact, pay-for-performance PPAs is the real benefit because it means the amount of risk can actually be lowered for everyone.

Ratepayer risk, as well as the opportunity and incentive for risk management, varies considerably by transaction type. It is best to think of the range of transaction types along a spectrum, which runs from a point at which most risks are assigned to ratepayers before the fact to a point at which most risks are assigned to bidders. We have a stylized picture of risk allocation across transaction types in Table III-One. The types of risks are shown as rows on the left side of the Table; we show four classes of risks (power plant development risk, operating risk, regulatory risk, and market risk) and have subcategories under all of these broader categories. Along the top of the table we have listed six transaction types. The first five generally cover the range invited by PacifiCorp; the sixth is for a transaction type called "full requirements default service," which reflects the competitive auctions and other solicitations in the East and Midwest that we cited in the introduction. A checkmark (✓) indicates that a risk is typically assigned before the fact to a power supplier under that transaction type. An empty box indicates a risk is assigned to ratepayers.

TABLE III-ONE: STYLIZED RISK MATRIX FOR TRANSACTION TYPES

(✓ indicates risk typically shifted to the supplier before the fact, an empty box indicates a risk is assigned to ratepayers)

Types of Risks	Cost-Plus Ratemaking	EPC Agreement	Asset Purchase (Plus O&M)	Tolling Agreement	Pay-for-Performance PPA	Full Requirement Default Service
1. Development Risk						
a. Installed Cost						
i. EPC		✓	✓	✓	✓	✓
ii. Soft Costs			✓	✓	✓	✓
iii. Finance			✓	✓	✓	✓
b. Reliability at Start		✓	✓	✓	✓	✓
c. Environmental Start		✓	✓	✓	✓	✓
2. Operating Risk						
a. Operating Cost						
i. Fuel Price					✓	✓
ii. Heat Rate				✓	✓	✓
iii. O&M				✓	✓	✓
b. Reliability				✓	✓	✓
c. Environmental				✓	✓	✓
3. Regulatory Risk						
a. Disallowance						
b. Environmental						
i. CO_2						✓
ii. Other				✓	✓	✓
4. Market Risk						
a. Need for Power						✓
b. Price of Power						✓

As shown in the Table, and as explained above, all risks are assigned before the fact to ratepayers under traditional cost-plus ratemaking; again, this is the transaction type PacifiCorp would use for its Benchmark Resources. This is not to say that PacifiCorp (or anyone under traditional regulation) is given an unlimited right to pass through any costs or unlimited forgiveness for any level of performance. We understand fully that the pass-through of higher costs, and the forgiveness of poor performance, is subject to after-the-fact prudence review. We understand, too, that the ratepayer uncertainty under cost-plus ratemaking goes both ways – costs could be lower than assumed in the Benchmark evaluation, and performance could be better.

As can be seen in the Table, as we go from left to right across the transaction types, more and more risks are assigned to the power supplier rather than to the ratepayer. For the transaction types invited to bid in the PacifiCorp RFP, the pay-for-performance PPA shifts the most risk. Again, this is not to say that such a PPA provides perfect risk protection. For example, risk assignment for fuel price may be in the form of a guaranteed heat rate with a fuel price indexed to a market indicator. Typically, natural gas prices in a PPA are indexed to published prices for natural gas deliveries to hubs. In this case, the ratepayer still faces fuel price uncertainty, but is protected against fuel price risks peculiar to the power plant – the risk that the heat rate will be higher than expected or that the fuel price for that plant will get out of line with market averages. Since fuel price risk is the most prominent risk for natural gas-fired plants, this limited risk shifting is notable.

We added the final column for Full Requirements Default Service simply to show that risk mitigation has moved beyond that in the pay-for-performance PPA. Specifically, market risk is now assigned to power suppliers in all of the default (or standard offer service) auctions and RFPs. This has to be qualified since these are short-term contracts with the longest generally being three years.

D. IE RECOMMENDATIONS

Ratepayer risk varies considerably across the transaction types invited to bid. The most notable difference is the higher ratepayer risk with cost-plus ratemaking for the Benchmark Resources as compared to the lower ratepayer risk with the pay-for-performance PPA. PacifiCorp has no plans to reflect that difference in risk in its bid evaluation. For this reason, its evaluation will be significantly deficient. Ratepayer risk is a key element of the deal ratepayers will get and it cannot be ignored.

Ratepayers would understand this. For example, they know that, at the start of a home mortgage, the interest rate generally will be higher with a fixed rate mortgage than with an adjustable rate mortgage; with the fixed mortgage, the mortgage supplier provides risk protection to the homeowner and the homeowner pays a premium for that risk protection. Similarly, ratepayers know that the expected return on a corporate stock must be higher than the interest rate on a Treasury Bill because the stock has much higher risk since the return is so uncertain. Put another way, if a ratepayer was offered the choice between (a) a ten-year Treasury with a 5% interest rate or (b) a corporate stock with a 5% *expected* return, the ratepayer would choose the Treasury because the lower risk of the Treasury makes it a better deal.

These examples show that consumers do not always see risk (uncertainty or variability) as a bad thing. Some consumers readily want risk – in an adjustable mortgage or in corporate stocks. However, difference in risk must be accounted for. PacifiCorp will not choose the best deal for ratepayers if it does not account for differences across transaction types. In a previous draft RFP, PacifiCorp said it *assumes* the benefits and risks of cost-plus ratemaking are offsetting.[27] This is not something to be *assumed* in a fair and transparent RFP; it is something that must be *proved.* There may indeed be ratepayer benefits to cost-plus ratemaking, and we know there are ratepayer risks. Both should be quantified.[28]

There are two ways to account for differences in ratepayer risks across transaction types. The first would be to quantify the risk (and the benefits) and add (or subtract) that percentage or dollar risk premium (discount) to the Benchmark Resources for evaluation. The second way would be to require that the Benchmark Resources be held to the same risk assignment standard as a pay-for-performance PPA.

[27] Draft RFP 2012, filed with the Oregon Commission 11/1/06, at page 52.

[28] While it may be beyond the scope here, we cannot fail to cite a very broad risk of cost-plus ratemaking: cost-plus eliminates the incentive for technological and managerial innovation. Why take on the risk of investing in innovation if there is no upside (no higher return), but a potential downside (disallowance)?

We recommend the second approach. PacifiCorp should be held to its estimate of annual costs and performance for its Benchmark Resources. The same risk assignment standard would apply to all transaction types. That is, each must match the risk assignment of the PPA. For example, if an asset purchase is evaluated and the purchase price serves as the starting point for a revenue requirement estimate, then PacifiCorp must be held to all the other elements of the revenue requirement estimate – capital additions, heat rate, fuel price index, etc. – in a manner that matches the risk allocation in the pay-for-performance PPA.

Accounting for the difference in ratepayer risk across the transaction types is essential to identify the best deal for ratepayers in terms of price, risk, reliability and environmental performance. Equally important, with an announcement that PacifiCorp will be held to its benchmark cost and performance estimate, the RFP should be more credible to competitors so that there are more bidders and bidders will bid more aggressively. Absent such an announcement, bidders may believe PacifiCorp has both the opportunity and incentive to understate costs and overstate performance for its benchmarks.

Accepting pay-for-performance risk, we believe, is also in the best interest of PacifiCorp's shareholders. Absent that acceptance, the risk allocation PacifiCorp has offered is unclear because it will be determined in *after the fact* prudence hearings. PacifiCorp may prevail in passing on higher-than-expected costs to ratepayers, but it may not. For example, the prudence standard may translate to a risk allocation in which PacifiCorp faces a cost cap (based on its cost and performance estimates today), but no cost floor (all cost savings are passed through to ratepayers). By accepting pay-for-performance risk, PacifiCorp would gain a symmetric opportunity to win or lose and be in a position to manage risk *before the fact*

When we say "held to its benchmark cost and performance" we mean quite literally that if a benchmark wins the RFP, its cost recovery is set equal to the cost and performance assumptions used to determine that it was the winner. For example, all bids and benchmarks include a "capacity cost payment ($/kw-mo)" that is used in evaluation.[29] Let us assume the capacity cost estimate for a benchmark is a fixed $200/kw-month, and the benchmark was assumed to be available 85% of the time. Being "held" to these estimates means the capital

[29] 2012 RFP at page 40.

revenue requirement for the benchmark is set at $200/kw-month for the assumed life of the benchmark, and it is earned only if the 85% availability factor is achieved. This is how a PPA works and the same standard should be applied to the benchmark.

It is our understanding that PacifiCorp has agreed that its benchmark will be held to its capacity cost payment. PacifiCorp will be allowed to index its capital costs in the same way bidders can.[30] This is a good step towards addressing our concern about cost-plus ratemaking. However, PacifiCorp has not agreed to be held to the other components of its benchmark estimates, such as capital additions and fuel cost, and this remains a concern for us.

IV. SIMILARLY, EVALUATION METHODS MUST ACCOUNT FOR DIFFERENCES IN RATEPAYER RISK ACROSS TECHNOLOGY TYPES

A. DEFINING THE ISSUE

If the RFP is to find the best deal for Oregon ratepayers, the evaluation methods must measure risk in a comparable manner across all alternatives. Such, comparability must also be guaranteed to entice bidders to bid and to encourage them to bid aggressively. Above, we discussed assuring comparable ratepayer risk across transaction types. Here we discuss assuring comparable risk across technology types.

The nature and extent of risk varies across technologies. For example, for coal-fired technologies the greater risks are linked to capital costs. Because coal is a capital-intensive technology it is important to account for uncertainty over the actual cost to finance and build coal-fired technologies. That capital risk can extend through the life of the power plant in terms of uncertain capital additions each year. The risk of environmental regulations also is more pronounced for coal because of typically higher emission rates. The history of sulfur dioxide regulations illustrates this point for the past. Going forward, the most prominent risk is for new regulation of CO_2. While capital and environmental regulation risks are the more notable risks attached to coal-fired technologies, fuel price risk should not be ignored; the cost of the coal commodity and of coal delivery also faces some uncertainty. For conventional coal technologies, performance risk (availability or reliability)

[30] At the request of the Utah Commission, PacifiCorp will allow bidders to index up to 40% of capital costs. Up to 25% may be indexed to the Consumers Price Index for Metals and Metal Products. See 2012 RFP at page 40.

is not thought to be a significant risk although issues can arise. For IGCC, because it is not a fully commercialized technology, performance risk may be more important.

In contrast, for natural gas, fuel price risk is the more prominent risk; recent history has made this abundantly clear. But, as with coal, other risks still have to be assessed – these include the risk of CO_2 regulations in the future. Performance risk is not thought to be a significant risk although issues can arise.

For renewables such as wind, performance risk is the more prominent risk. This is reflected in an assumed capacity value for the technology and in the assumed pattern or timing of energy deliveries. Major advantages of some renewables can include that there is no fuel price risk or risk of future CO_2 regulation. Other renewable technologies (biomass and geothermal) may have fuel availability risk and emission risks, too. Performance risk also would appear to be the prominent risk for demand-side technologies; the same benefits would apply.

To find the best deal for Oregon ratepayers, these differences in the nature and extent of risk must be accurately measured in the evaluation process.

B. PACIFICORP APPROACH TO THE ISSUE

PacifiCorp's approach to risk analysis varies for the Initial and Final Shortlists. For the Initial Shortlist, PacifiCorp states that it will base the selection on price and non-price factors:

> The selection of an initial shortlist of bids will be based on price and non-price factors taking into account resource diversity of the term and fuel source. The price factor will be derived, in the initial shortlist analysis, using the PacifiCorp Structuring and Pricing RFP Base Model. The RFP Base Model will be used to establish the initial shortlist of the top performing proposals by fuel type in each of the Eligible Resource Alternative categories specified in the RFP based on the projected net present value revenue requirement (net PVRR) per kilowatt month (Net PVRR/kW-mo). The non-price factors will evaluate the proposed resource characteristics, including development feasibility and risk, site control and permitting, and operational viability and risk impacts.[31]

[31] 2012 RFP at page 45.

Note that the term "net" refers to the fact the bidder's price offer will be compared to a forecast of market prices. The *lower* the bid price is as compared to the forecasted market prices for energy and capacity, the *higher* the net PVRR.[32] Non-price factors also will be evaluated; the relative weight given to price and non-price factors is 70% and 30% respectively.[33] The non-price factors are something of a risk analysis for the Initial Shortlist in the sense that they assess development feasibility, site control and permitting, and operational viability.

The Initial Shortlist is just a screening tool to narrow the number of bids to evaluate for the Final Shortlist. But the narrowing is limited on purpose in two ways. First, on price, all bids at or below 80% of the market forecast get the full 70% weight.[34] Second, it is not just the top-ranked bid that is chosen from each transaction type. PacifiCorp says it will keep for each transaction type "up to two times the approximate megawatt needs for each year."[35] Moreover, it now will reflect fuel type in the ranking.

For the Final Shortlist, PacifiCorp conducts a sophisticated modeling exercise to assess risks. PacifiCorp will conduct both "stochastic" and "scenario planning" analyses. We presume here that the analysis is of the sort done for the IRP.[36] With that assumption, based on the 2004 IRP, the stochastic analysis assesses five risks over the operating life of the technologies. Those five risks are (a) retail loads; (b) natural gas price; (c) wholesale electricity price; (d) hydro electric generation; and (e) thermal unit availability. A possible range for each of these risks is determined based on historical experience and the risk model determines randomly in each run what is assumed.[37]

For each portfolio of alternatives -- a portfolio combines various alternatives such as coal-fired and gas-fired technologies, DSM, renewables and purchases to satisfy customers' needs -- PacifiCorp will estimate the net PVRR under 100 different sets of assumptions. That is, the cost (net PVRR) of each portfolio will be estimated with 100 model runs.

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32 2012 RFP at page 49 ("the value of the energy and capacity").
33 Ibid.
34 2012 RFP at page 49.
35 Ibid., at page 53.
36 Ibid.
37 2004 IRP at page 62.

PacifiCorp states that the following risk measures will be calculated for each portfolio based on these 100 model runs.

> Stochastic average PVRR. Defined as the sum of the stochastic average variable cost (for 100 iterations) plus the deterministic fixed cost, this measure represents the expected value of total PVRR based on stochastic operating cost inputs.
>
> Fifth and ninety-fifth percentile PVRRs. The PVRR values corresponding to the iteration out of the 100 that represents the fifth and ninety-fifth percentiles, respectively. These metrics represent snapshot indicators of low-risk and high-risk stochastic outcomes.
>
> Upper-tail average stochastic PVRR. This metric is the mean of the five highest-PVRR iterations, and represents a measure of high-end volatility risk exposure. It is a form of Conditional Value Risk (CVaR).
>
> Difference between the upper-tail average stochastic PVRR and the stochastic average PVRR. This metric is another measure of high-end volatility risk exposure. It represents the maximum expected loss (additional portfolio cost) up to the level defined by the upper-tail average stochastic cost.
>
> Average Energy Not Served (ENS). This metric is the average number of GWh un-served for the 100 stochastic simulation iterations. ENS is the amount of load that is not met by system resources or purchases. It represents a measure of supply resource-related system reliability.[38]

Among these measures of risk, PacifiCorp states that the "upper tail minus average" measure "is viewed as the principal portfolio risk screening metric.[39]

PacifiCorp states that it will conduct scenario planning analyses in the 2012 RFP for CO_2, fuel prices (both natural gas and coal), and electricity prices.[40] With respect to the varied levels of CO_2 taxes, PacifiCorp stated in its 2004 IRP that:

> The base case CO_2 emissions allowance charge is assumed to be $8 (2008 dollars) per ton starting in 2012. Further it is assumed that there is a 50% probability of the emissions allowance charge beginning in 2010 and a 75% probability of the charge beginning in 2011. As a result of these assumptions

[38] 2004 IRP Update at pages 41 and 42.
[39] Ibid., at page 42.
[40] 2012 RFP at page 53.

the \$8 value is multiplied by the probability of occurrence for these years. Associated with this CO_2 emissions allowance charge assumptions are the NO_x, SO_2, and H_g (mercury) price adders, as well as the natural gas and electric power price assumptions.

Four CO_2 emissions allowance charge scenarios were analyzed during this IRP cycle. Three of the CO_2 scenarios are in compliance with Oregon 93-695 dated May 17, 1993. The Order requires that IRP analysis be formed with the CO_2 emissions allowance charges varying at values of \$10, \$25, and \$40 per ton in 1990 dollars. An additional scenario was performed during this IRP cycle which set the value of the CO_2 emissions allowance charges at \$0 per ton in order to measure the impact of no emissions.[41]

C. IE DISCUSSION OF THE ISSUE

The goal is to assure that the ratepayer risks from the various alternatives is accurately measured in the RFP evaluation. PacifiCorp builds in significant risk assessment to its bid and benchmark evaluations and should be given credit for doing so. Here we will note eight remaining areas of concern.

First, the non-price factors constitute the risk analysis for the Initial Shortlist. The three risks to be scored concern project development feasibility, site control and permitting, and operational viability. The scoring is now more precise than in previous drafts; only three scores will be assigned – 0%, 50%, and 100%. But the basis for assigning these scores leaves substantial discretion to PacifiCorp. The Oregon IE will have to determine if these non-price risks actually make much of a difference in the choices for the Initial Shortlist at the time of evaluation. If so, then we will be more vigilant in assessing comparability across bids.

Second, we do not see diversity across transaction types as being the correct screen. It is diversity across technology types and fuel types, which makes a difference for ratepayers in terms of risk mitigation; risk mitigation would arise if the risk of the diverse technologies were fundamentally different. Given this, PacifiCorp's decision to have fuel type drive the choice within transaction type is a good step forward.

Third, the risk assessment for the Final Shortlist excludes capital cost risks. As noted above, the greater risks for coal-fired technologies are with capital costs - both the final

[41] 2004 IRP at page 155.

installed costs as well as capital additions over the life of the plant. Technologies that are not fully commercialized have these risks, too, and the risks are more pronounced than with conventional technologies. PacifiCorp should conduct risk analysis on capital cost in either the stochastic or in the scenario planning analysis (perhaps the more appropriate method for capital cost risks). However, if all alternatives, including PacifiCorp's Benchmark Resources, are required to offer indexed prices for capacity, then this risk analysis can be limited to the bounds of that indexing.

This risk has been made tangible by recent testimony in a Duke Power proceeding in North Carolina. Soon after presenting its cost estimate for its proposed new coal unit at one of its existing plants, in 2006, Duke returned to tell the State Commission its capital cost estimate increased by 40%.[42] Duke presented other testimony stating that capital costs for coal plants have increased by 90% to 100% since 2002.[43] This same witness reported capital cost increases for all technologies. The presence of capital cost risk is clearly evidenced by this recent experience.

Fourth, the risk assessment does not address fully the Commission's concern with surplus power sales when the power is not needed by PacifiCorp customers. While PacifiCorp does assess this risk in the sense that it allows for varied wholesale power prices, it does not consider the risk that such power sales could be denied altogether due to environmental regulations such as those on CO_2 for the state of California. PacifiCorp may claim it anticipates short-term sales while California's regulation targets long-term sales. However, the question should be viewed in strategic terms; that is, to what extent do these Benchmarks depend on sales, especially to California?

Fifth, while coal prices are thought to be less volatile than natural gas prices, it does not mean that there is no uncertainty about the price to mine and deliver coal. Appropriately, PacifiCorp now plans to assess the risk of delivered coal price volatility.

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[42] North Carolina Utilities Commission. In the Matter of Application of Duke Energy Carolinas LLC for Approval for an Electric Generation Certificate of Public Convenience and Necessity to Construct Two State of the Art Coal Units for Cliffside Project, Docket No. E-7, Sub 790, Supplemental Testimony of James E. Rogers, CEO Duke Energy Corp. November 29, 2006..
[43] Ibid. Supplemental Testimony of Judah Rose, November 29, 2006.

Sixth, with respect to natural gas price volatility, PacifiCorp should be prepared to assess a fixed price offer from a gas-fired technology. That is, its evaluation must give risk credit for fixed price natural gas proposals. We understand that it will.

Seventh, it is unclear how PacifiCorp precisely plans to conduct an assessment of future CO_2 regulation. As explained more fully in the section on the risk of such regulation, PacifiCorp should test the Final Shortlist with the range of CO_2 taxes it used in its original 2004 IRP. Further, it should test the technologies under a strict, facility-based CO_2 emissions standard. The goal of the CO_2 risk assessments should be to show the "tipping points" for technologies. That is, at what level of CO_2 tax (or with what type of facility regulation) does the technology choice tip from conventional coal to bids for (a) natural gas-fired technologies; (b) to geothermal or biomass technologies or other renewables; (c) to DSM technologies; (d) to IGCC or other "clean" coal technologies.

Eighth, PacifiCorp plans only generic assessments of the risk of performance. Some assessment should be done for each proposal. This risk analysis should be dictated by the extent of availability guarantee in each transaction contract, including such guarantee (or lack thereof) for the Benchmark Resources.

D. IE RECOMMENDATIONS

We recommend that the eight remaining concerns defined above in the *IE Discussion* be addressed as discussed.

V. THE RISK OF FUTURE CO_2 REGULATION MUST BE ADDRESSED EXPLICITLY AND THOROUGHLY DESPITE THE SIGNIFICANT UNCERTAINTY

A. DEFINING THE ISSUE

To many observers, the evidence of global warming has become increasingly plentiful and credible in just the past few years.[44] Certainly it is possible that the U.S. will pass

[44] Policy Implications of Greenhouse Warming: Mitigation, Adaptation, and the Science Base. Committee on Science, Engineering, and Public Policy (COSEPUP) of the National Academy of Sciences (NAS). National Academies Press: Washington, DC,1992. Surface Temperature Reconstructions for the Last 2,000 Years. National Research Council. The National Academies Press, Washington, DC: 2006. Sir Nicholas Stern, Report on the Economics of Climate Change From the U.K. Treasury website.

legislation to address this concern during the lifetime of the power plants being bid into the RFP. Such legislation is likely to regulate carbon dioxide (CO_2) emissions. CO_2 regulation represents a substantial financial risk to ratepayers *if ratepayers bear the risk of compliance*, and this appears to be the intent of PacifiCorp's 2012 RFP.

For purposes of the 2012 RFP, the question is this: To what extent should the risk of CO_2 regulation be considered a ratepayer risk, and in what specific way should that risk be quantified?

B. PACIFICORP'S APPROACH TO THE ISSUE

In the RFP, PacifiCorp states that Bidders will be allowed to (and assumed to) pass through CO_2 emissions compliance costs to PacifiCorp. It states that: "As such, even if the bid does not provide for the passing through of such costs, the bid evaluation process will incorporate the assumption that Bidders will pass through to PacifiCorp any costs associated with meeting future air quality requirements relating to specified facilities."[45] "[A]ny changes to contract pricing based on CO_2 compliance costs will be subject to review and approval by the Utah Commission prior to passing through to customers."[46] This means that, while pass through is not a certainty, it remains a ratepayer risk.

C. IE DISCUSSION OF THE ISSUE

Significant uncertainty surrounds the CO_2 regulation issue. The possibilities range from no further regulation to a flexible cap and trade system to plant-by-plant standards. It is especially difficult to choose the most appropriate measure of risk in the bid evaluation because, ultimately, the decision is political. The following review of current legislative proposals, some actual market experience, and recent studies reveals a likely range of compliance costs or taxes to be imposed on CO_2 emissions.

California

Some of the most aggressive and well-publicized legislative actions are being taken by California. California's Global Warming Solutions Act of 2006 requires a 25% cut in the

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"Independent reviews: Index." HM Treasury. http://www.hm-treasury.gov.uk/independent_reviews/independent_reviews_index.cfm. Accessed 1/16/07.

[45] 2012 RFP at pages 39-40.

[46] 2012 RFP at page 57.

state's greenhouse gas emissions by 2020. Senate Bill (SB) 1368 ordered the California Public Utility Commission (CPUC) to establish a greenhouse gas emissions performance standard for the baseload generation of local load-serving entities. Importantly, that standard cannot exceed the CO_2 emissions rate of a combined-cycle gas turbine (CCGT) power plant.[47] The Global Warming Solutions Act has also set up a process to evaluate and establish a regional emissions trading exchange similar to the European Union's (EU) Emissions Trading Scheme or the Regional Greenhouse Gas Initiative (RGGI) of New England. In addition, the California Legislature has given a clear mandate for renewable power and "zero- or low-carbon generating resources," while impeding increases in CO_2-intensive generation through SB 1368.[48]

The CPUC has expressed its sentiment towards greenhouse gas (GHG) emissions as this: "it is likely that GHG emissions will be regulated within the timeframe addressed in the utilities' LTPPs [long term procurement plans] and the lifetime of the utilities' long-term resource commitments. Therefore, it is appropriate for us to consider policies that would limit the exposure of IOU [Investor Owned Utilities] ratepayers to risks associated with this future regulation."[49] Therefore, in 2004, the CPUC directed all California utilities "to employ a GHG adder when evaluating fossil and renewable bids received via an all-source RFO [Request for Offers]."[50] The CPUC estimated the financial risk associated with GHG emissions to be between $8 and $25 per ton of CO_2 and instructed the state's utilities to select a CO_2 emissions adder in that range for resource planning. Intervening parties were allowed to comment on the appropriateness of the number, and the number would be incorporated into the RFO analytic process.[51]

Since then, the CPUC President has called for and the full CPUC has approved an emissions performance standard (EPS) in the near term before "an enforceable load-based

[47] California SB 1368 text: "(l) The 2005 Integrated Energy Policy Report adopted by the Energy Commission recommends that any greenhouse gases emission performance standard for utility procurement of baseload generation be set no lower than levels achieved by a new combined-cycle natural gas turbine."
[48] SB 1368 continues (p.4e,i) : "New long-term financial commitments to zero- or low-carbon generating resources should be encouraged...[the emissions performance standard] will reduce potential financial risk to California consumers for future pollution-control costs."
[49] CPUC Rulemaking Order 04-04-003 filed April 1, 2004. Decision 04-12-048. p. 146. LTPPS stands for Long Term Procurement Plans and is essentially an IRP.
[50] Ibid. p. 152. An RFO is comparable to an RFP.
[51] Ibid. p. 152.

GHG emissions limit is established."[52] The standard corresponds to SB 1368's requirement that new baseload generation should have GHG emissions rates no higher than that of a CCGT power plant.

EU ETS and RGGI

The European Union Emission Trading Scheme (EU ETS) is the first, and largest, multi-national, greenhouse gas emissions trading scheme in the world. It was set up in an attempt to adhere to the Kyoto Protocol and many initiatives, such as RGGI, hope to emulate it.[53]

The EU ETS began trading in January 2005 with prices at € 8 ($10.40)[54] per ton of CO_2 and steadily climbed to a primary range between € 15 and € 26 ($19.50-$33.80) per ton of CO_2 for the period from March 2005 to August 2006.[55] Prices temporarily plummeted in April of 2006 when it was determined that an excess of emission permits had been granted. This widely-acknowledged market design error has gradually worn away the cost per ton of emitting CO_2 to a price around € 4 ($5.20) per ton, as of January 10, 2007.[56]

The Regional Greenhouse Gas Initiative (RGGI) expects similar prices for the nine New England states participating in the regional cap-and-trade program. RGGI has set a $10 (2005$) per ton of CO_2 "safety valve" price that permits additional time for compliance if the price is exceeded.[57] RGGI plans to cap regional emissions at a level approximately equivalent to 1990 emissions.[58]

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[52] CPUC President Peevey's "Interim Opinion on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard." Rulemaking 06-04-009. Filed 4/13/2006.
[53] Stern p. 327.
[54] Values are converted at a rate of € 1 = $ 1.30.
[55] Stern. p. 328.
[56] "EU tries to combat climate change with tough CO_2 cut." Mason, Jeff and Wynn, Gerard. Reuters. http://today.reuters.com/news/articlenews.aspx?type=scienceNews&storyID=2006-11-29T184209Z_01_L29227908_RTRUKOC_0_US-CARBON-EU.xml. 11/29/06.
Report on the Economics of Climate Change. Stern Review. www.sternreview.org.uk. 11/27/06. p. 329.
"EU Environment Chief Downplays Need for Higher CO2-Permit Costs." Stearns, Jonathan. Bloomberg News. http://www.bloomberg.com/apps/news?pid=newsarchive&sid=a0n8kZajf4VE. 6/16/06.
[57] "Regional Greenhouse Gas Initiative – Overview."
http://www.rggi.org/docs/mou_rggi_overview_12_20_05.pdf. 12/5/2005. Mechanisms are built into RGGI to avoid cost spikes by allowing flexibility. For example: "Safety Valve. If the RGGI allowance price equals or exceeds $10/ton (2005$) for twelve months (following an initial 14-month "market settling" period at the beginning of each compliance period), the compliance period will be extended for one year, up to a total three year extension. (The trigger price will escalate at 2% per year, beginning in 2006.)" Also, section 2.F.(3)(a) is described as: "Offsets Trigger. The offsets limit, and the geographic scope of

Other Indications

There are other indications of the overall risk of CO_2 regulation and the possible cost of implementation.

- In December 2004, the Governor's Advisory Group on Global Warming issued its recommendations for Oregon to comply with the West Coast Governor's Global Warming Initiative of 2003. The Group proposed arresting the growth of Oregon's GHG emissions by 2010 as one of the primary goals. Furthermore, they set a goal for a 10% reduction of emissions below 1990 levels by 2020.[59]

- Over the past two years, numerous bills have been presented in the U.S. Senate and House. No less than seven bills were presented to the 108th and 109th Congress, including those by Senators Bingaman, McCain-Lieberman, Udall-Petri, Feinstein, Kerry-Snowe, Waxman, and Jeffords-Boxer.

- Idaho Power estimates a 70% probability of carbon regulation with a compliance cost above $12.30/ton in 2008 and used a $14/ton of CO_2 adder in its 2006 IRP,[60] while many others (PG&E, Xcel/PSCo) assume regulation in 2009 with compliance costs above $6/ton CO_2.[61]

- In its 2006 IRP Public Input Meetings, PacifiCorp acknowledged that many proposals would involve a tax (or compliance cost) between $15 and $35 by 2020.[62]

- The British report (Stern Review or Report on the Economics of Climate Change) is one of the most recent, comprehensive analyses detailing the

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eligible offsets, will be expanded if the RGGI allowance price equals or exceeds $7.00/ton (2005$) for twelve months (following an initial 14-month "market settling" period at the beginning of each compliance period)." Generators are then able to use offsets for up to 5.0% of their reported emissions to meet compliance criteria.

[58] Ibid. p. 1

[59] "Oregon Strategy for Greenhouse Gas Reductions." Governor's Advisory Group on Global Warming, State of Oregon. December 2004. p. iv.

[60] Idaho Power 2006 IRP. Revised 10/12/06. At page 79.

[61] "An Overview of Alternative Fuel Price and Carbon Price Scenarios." Wiser and Bolinger. Berkeley National Laboratories. http://eetd.lbl.gov/ea/ems/reports/56403.pdf. October 2004. p. 25.

[62] "2006 Integrated Resources Plan Public Input Meeting" slideshow. PacifiCorp. 4/20/2006. p. 8, 18.

probability of outcomes from global warming. The report states that stabilizing the concentration of CO_2 in the atmosphere between 450-550 ppm should limit the likelihood of a 2°C global average temperature rise and subsequent "major disruption to economic and social activity." It estimated that a tax of $25 to $30 per ton of CO_2 would be associated with stabilizing CO_2 in the atmosphere at a reasonable level.[63] The report goes on to determine that the cost impact under a "Business as Usual" emissions trajectory (without regulation) would be as high as $85/ton CO_2.[64]

- However, these lower tax levels stand in contrast to a study published in Science magazine, which assert that a cost adder over $150 is necessary by 2050 to reduce the probability of "dangerous climate change" to less than 1%, assuming the median threshold for climate change to be at 2.85°C.[65]

- Currently, one of the Senators receiving heavy attention for a bill addressing Global Climate Change is Sen. Jeff Bingaman, Chairman of Energy and Natural Resources Committee. His "National Energy and Environmental Security Act of 2007" bill proposes utilizing a cap and trade program to reduce the US's 'energy intensity' (GHG emissions/GDP) by 2.6% per year, starting in 2012 and increasing to 3%/year in 2022. It includes a 'safety valve' provision that "allows regulated entities to pay a pre-established emissions fee in lieu of submitting an allowance."[66] An EIA study of Senator Bingaman's proposal acknowledged that emissions would still grow by 24% until 2030, half of the reference case without CO_2 regulation. The EIA finds that increasingly heavy allowance prices are expected to shift energy decisions by 2030.[67] In 2030, allowance prices are

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[63] Report on the Economics of Climate Change. Stern Review. www.sternreview.org.uk. 11/27/06. p. 304. "But along a trajectory towards 550 ppm CO_2e, the social cost of carbon would be around $30/t$CO_2$ and along a trajectory to 450 ppm CO_2e around $25/t$CO_2e$. These numbers indicate roughly where the range for the policy-induced price of emissions should be if the ethical judgments and assumptions about impacts and uncertainty underlying the exercise in Chapter 6 are accepted." (304)
[64] Ibid. p. xvi, 304.
[65] "Probabilistic Integrated Assessment of "Dangerous" Climate Change." Mastrandrea, Michael D. and Schneider, Stephen H. Science. April 23, 2004. p. 571-574.
[66] "Energy Market and Economic Impacts of a Proposal to Reduce Greenhouse Gas Intensity with a Cap and Trade System." Energy Information Administration. January 2007. p. v.
[67] Ibid. p. vii.

projected to be between \$10-18/ton CO_2e, whereas they are projected to be between \$3-4.25 in 2012.[68]

- Another heavily publicized bill was put forth by Senators McCain and Lieberman. Their proposal is more comprehensive and stringent. It seeks a cap-and-trade program to limit emissions to 2000 levels by 2015, and return to 1990 levels by 2020. A MIT study of the proposal determined that the cap would correspond to CO_2e price range from "under \$20 to nearly \$40 in 2010, rising to about \$30 to \$65 by 2020."[69]

D. IE RECOMMENDATIONS

Our goal is to assure clarity on two topics: (a) the nature and extent of the CO_2 compliance risk that is imposed on Oregon ratepayers and (b) the method for incorporating the risk of future CO_2 regulations in the evaluation of Benchmarks and bids.

With respect to ratepayer risk, PacifiCorp has made it clear that any pass through of CO_2 compliance costs would be subject to review and approval by the Utah Commission. This addresses the immediate concern about open-ended risk, but we would have preferred more detailed answers to key questions: What is the legal standard for the proceeding? If the standard is prudence, what does prudence mean? Is the goal to find the lowest-cost compliance plan for that supplier? Or is the goal to find the lowest-cost source of power at the time the regulations are imposed? May the Commission decide that terminating a PPA is prudent and, if so, how is compensation determined? May the supplier terminate the PPA and would there be compensation? The contractual rights and obligations have to be spelled out and must be comparable for the Benchmark Resources.

With respect to evaluation, PacifiCorp should be clear that it intends to use the \$8 per ton tax on all proposals for both the Initial and Final Short lists. And, PacifiCorp should be clear that it intends to conduct scenarios risk analyses as it has in the past. Historically, PacifiCorp has used \$0, \$10, \$25, and \$40/ton CO_2 in its scenario risk evaluations of future

[68] Ibid. p. 10.
[69] "Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal." Paltsev, Sergey, et al. MIT Joint Program on the Science and Policy of Global Change. June 2003. p. 27.

portfolio.[70] Though PacifiCorp recognized the extent of potential risks for CO_2 emissions regulation in its IRPs in this way, the current RFP process does not clearly do so. Although there is significant uncertainty, based in our review of recent studies above, sensitivities conducted with taxes in the $20 to $40 range seem appropriate.[71]

We believe that PacifiCorp should use these sensitivities to determine a "tipping point," where the cost of CO_2 emissions would tip the PVRR in favor of one resource over another. In particular, at what cost per ton of CO_2 emissions does natural gas become more economical than pulverized coal, and at what cost per ton of CO_2 emissions does IGCC become the most economic resource and so on? In addition, to fully inform the Commission, PacifiCorp should show the results of a CO_2 emissions standard as opposed to a tax (or comparable cap and trade system). PacifiCorp appears to address this in its 2004 IRP update.[72] For example, PacifiCorp should assess the PVRR for conventional coal and IGCC when both must meet a common standard. PacifiCorp has noted that "the potential for IGCC to offer more economical CO_2 capture as compared to conventional coal plants represents the most compelling environmental reason to employ the technology for power generation."[73] PacifiCorp has also made it clear that multiple portfolios will be established – "an optimal portfolio will be established for each combination of emission and wholesale market and natural gas price assumptions."[74] Assessing multiple portfolios should get us to the point at which "tipping points" can be determined, but PacifiCorp has not committed to doing so.

[70] "2006 Integrated Resources Plan Public Input Meeting" slideshow. PacifiCorp. 4/20/2006. p. 19. PacifiCorp 2003 IRP. P. 39, Appendix C P. 284-287. PacifiCorp 2004 IRP, p. 63. IRP analyses use allowance rates in 1990 dollars.

[71] We believe the extremes of this range would adequately correspond to potential national legislation (MIT study of the McCain-Lieberman Bill, "under 20[dollars]" in 1997 dollars), potential local legislation (CPUC order for an $8-25 (2004 $) cost adder for long-term procurement), or social cost (Stern review stabilization estimate of $25-30 (2000 $)).

[72] At page 25 and Figure 3.1.

[73] PacifiCorp 2004 IRP Update. 11/3/05. p. 25-26..

[74] Ibid., at page 51.

VI. EVALUATION METHODS MUST FULLY ASSESS THE OPTION VALUE OF SHORTER-TERM OFFERS

A. DEFINING THE ISSUE

Shorter-term offers can give ratepayers option value in the sense that, if market or regulatory conditions change significantly in the future, PacifiCorp can move from these contracts (when they expire) to options better suited to the changed circumstances. To assure this option is assessed, it is important that there is no bias against shorter-term offers in the selection of either the Initial or Final Shortlist.

The issue is a common business problem comparing options with unequal lives. Central to all methods of comparing alternatives of unequal lives is the assumption about what happens when the shorter-term choice expires. The concern is that the evaluator can have significant discretion determining those assumptions, which could lead to a bias in the evaluation.

According to standard financial history, the Equivalent Annual Cost Method, or simply the Annuity Method, should be used to compare alternatives that have unequal lives.[75] An annuity is the equal annual payment over the life of the alternative that has the same present value as the actual, unequal annual costs that are expected to be incurred. A ten year bid would calculate the annuity over ten years and a five year bid would have a five year annuity. The alternative with the lower annuity is the better choice.

B. PACIFICORP'S APPROACH TO THE ISSUE

We understand that an annuity method is used for the Initial Shortlist so the concern would be allayed there.

For the Final Shortlist, a "fill-in" method is used to account for differences in term length. Based on discussions with PacifiCorp, we understand offers will be evaluated for 20 years and, if an offer was made for say 10 years, the remaining 10 years would be filled in with an assumed replacement source of power. PacifiCorp uses two reasonable assumptions

[75] See Ross, Stephen A., Westerfield, Randolph W., and Jaffe, Jeffrey. Corporate Finance Fourth Edition Irwin. (1996) p. 85.

for replacement power: (a) spot market purchases and (b) a new generic power plant such as a combined cycle plant.

C. IE DISCUSSION OF THE ISSUE

Both of PacifiCorp's assumptions, while reasonable, have the downside, in effect, assuming this winning bidder goes away – it is not available to bid and win again in a future RFP. This is especially troublesome if the bid has a specific power plant behind it. Another downside is that it gives PacifiCorp too much discretion.

To address these downsides, we suggest using one or two other assumptions to reveal any possible bias against short-term offers. Both of the two we suggest have the appeal of letting the original offer "speak for itself." One is simply to take the original offer and escalate it for cumulative inflation as appropriate. The second is to assume the bidder would offer a price in the same proportion to market prices in the future as it did when it won the original RFP – we understand that Commission Staff asked Portland General Electric to use this as another scenario in its RFP in 2003.[76] These two added analytical assumptions would be used as sensitivity analysis to see if the nature of the preferred portfolio would change.

D. IE RECOMMENDATION

To avoid possible bias, we recommend that PacifiCorp use the two additional methods for "filling in." PacifiCorp would then report if these alternatives change its selections in the Final Shortlist.

VII. BIDS AND BENCHMARKS MUST BE ASSESSED COMPARABLY IN TERMS OF WHAT IT TAKES TO BE A NETWORK RESOURCE. WHO PAYS FOR TRANSMISSION UPGRADES MUST BE CLEAR.

A. DEFINING THE ISSUE

PacifiCorp requires that resources offered in the 2012 RFP be Network Resources. PacifiCorp states:

[76] Oregon PUC Docket No. LC 33 (PGE). "Staff Report." 5/19/04. at page 18.

> The scope of this Request for Proposals ("RFP"), subject to the limitations described herein, is focused on all Base Load supply-side resources capable of delivering energy and capacity in or to the Company's Network Transmission system in the Company's Eastern Control Area ("PACE") and that **fulfills the requirements of being a Network Resource.** [Emphasis added][77]

Put simply, Network Resource status requires that the offered resources can be delivered reliably to serve load, including under contingencies. It is crucial that the assessment be done comparably for all bids and benchmarks; finding evidence of comparability will be a key task for the IE at the time of evaluation. To be granted Network Resource, a bidder may have to pay for both transmission interconnection and integration investments. In our experience with other solicitations, concerns have been raised over bias for benchmarks. For example, a utility may transfer Network Resource status to its benchmark to avoid integration costs or Network Resource status can be granted to a benchmark with more flexibility (e.g. operating guidelines), again, to avoid integration costs.

At the start, PacifiCorp must be clear on whether interconnection and integration costs must be reflected in bid prices. Without this clarity, different bidders will take different approaches, and apples-to-apples evaluation will not be possible.

B. PACIFICORP'S APPROACH TO THE ISSUE

See discussion below.

C. IE DISCUSSION OF THE ISSUE

PacifiCorp addresses both interconnection and integration costs. For interconnection cost, PacifiCorp states:

> All proposals that will require a new electrical interconnection to the PacifiCorp Transmission system or an upgrade to an existing electrical interconnection to the PacifiCorp Transmission system must include a statement of the cost of interconnection, together with a diagram of the interconnection facilities. The Bidder will be responsible for, **and is required to include in its bid,** all costs to interconnect to the PacifiCorp's Transmission system. [emphasis added] ...**Bidders are reminded that they**

[77] 2012 RFP at page 4.

shall bear 100% of the costs to interconnect to PacifiCorp's Transmission System.[78]

From this, it seems clear that the bidder pays the investment cost and must include recovery of that investment in its bid price; a PPA might include this in the capacity price. But then some confusion is created when PacifiCorp states: "...PacifiCorp's Transmission function has the option of funding the interconnection upgrades or requiring the Bidder or Benchmark to fund such upgrades and then receive revenue credits. Any such refunds shall be assigned to the company."[79] PacifiCorp needs to clarify the meaning and impact of this.

In contrast, bidders are directed to omit transmission system integration costs from their bid prices. However, PacifiCorp will include integration costs for both bids and benchmarks in its evaluation.[80]

D. IE RECOMMENDATION

The instructions now seem clear and only the one clarification noted above needs to be made. And, again, comparability in the actual evaluation will be key.

VIII. TO ATTRACT BIDDERS AND PROMOTE AGGRESSIVE BIDDING, REGULATORY UNCERTAINTY SHOULD BE MINIMIZED AND MITIGATED

A. DEFINING THE ISSUE

Regulatory uncertainty is one of several risks that a bidder must account for in his/her offer; it most likely contributes to the risk premium reflected in the price offer. One source of such uncertainty is the fact that, in PacifiCorp's multi-state environment, there is disagreement over the level and nature of need for the 2012 RFP.

B. PACIFICORP APPROACH TO THE ISSUE

PacifiCorp is clear that it "is seeking up to 1,700 MW of cost-effective Base Load resource(s) for delivery in 2012, 2013, and/or 2014."[81] It further defines Base Load as follows:

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[78] 2012 RFP at pages 43 and 44.
[79] Ibid., page 44.
[80] Ibid.

> The scope of this Request for Proposals ("RFP"), subject to the limitations described herein, is focused on all Base Load supply-side resources capable of delivering energy and capacity in or to the Company's Network Transmission system in the Company's Eastern Control Area ("PACE") (www.oasis.pacificorp.com) and that fulfills the requirements of being a Network Resource. A Base Load supply-side resource is defined as any resource with any type of fuel source that provides unit contingent of firm capacity and associated energy that are incremental to the Company's existing capacity and energy resources and are available for dispatch or scheduling by June 1, 2012, June 1, 2013 and/or June 1, 2014.[82]

In this context, PacifiCorp clarifies the type of resource need to be filled with the RFP in terms of two benchmark resources.[83] The first benchmark is a 340-MW share of the planned 900-MW, conventional coal-fired Intermountain Power Project (IPP) Unit 3 scheduled for 2012; IPP is an existing coal-fired power plant with two other comparable units in operation in Utah.[84] The second benchmark gives two alternatives for 2014. One alternative is a 527-MW share of a 790-MW conventional, coal-fired plant at the existing Jim Bridger site The other alternative is a 500-MW IGCC, coal-fired power plant in Wyoming at the Jim Bridger power plant site; the Jim Bridger plant has four existing coal-fired plants.[85]

Later when discussing its bid evaluation methods, PacifiCorp states that, for the model used to establish the final shortlist, its "assumptions will be conceptually consistent with the *2006* Integrated Resource Plan (IRP) high, medium, and low cases, but may reflect more recent data at the time the analysis is conducted."[86]

C. IE DISCUSSION OF THE ISSUE

As already noted, the Commission set forth revised competitive bidding guidelines in its Order No. 06-446 which was issued on August 10, 2006. In that Order, the

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[81] 2012 RFP at page 7.
[82] 2012 RFP at page 4.
[83] 2012 RFP at page 5.
[84] 2012 RFP Appendices, Attachments and Forms at page 107 and ipautah.com.
[85] 2012 RFP Appendices, Attachments, and Forms. At pages 109-114. And: Gearino, Jeff. "Power plant, coal mine celebrate 30 years." Casper StarTribune.net. http://www.casperstartribune.net/articles/2004/08/21/news/wyoming/05c2e76ff62d8ecf87256ef60080b525.txt. 8/21/04. Accessed 3/2/07.
[86] 2012 RFP at page 50.

Commission essentially reaffirmed five goals it had set for competitive bidding back in 1991. Second among those five goals was that competitive bidding should "Complement Oregon's integrated resource planning process."[87] Later in the bidding guidelines, when discussing guideline 7, *RFP Approval*, the Commission put a somewhat finer point on the issue when it said that public comments and the Commission's own review should focus on the "alignment of the utility's RFP with its acknowledged IRP."[88]

On January 16, 2007, in Order No. 07-018, the Commission concluded that the draft 2012 RFP submitted to the Oregon Commission on November 1, 2006 was not aligned with the acknowledged IRP. And, further, the Commission denied PacifiCorp's request for approval of its draft RFP.[89]

As background, note that the Guidelines call for alignment with an *acknowledged* IRP. In Order No. 06-029, dated January 23, 2006, the Commission acknowledged PacifiCorp's 2004 IRP, but importantly, did so with two exceptions.[90] The Commission stated, "Therefore, we decline to acknowledge either the 550 MW flexible resource (modeled as a gas-fired CCCT) or a 600 MW high capacity factor resource (modeled as a pulverized coal plant) in, or delivered to, Utah by CY 2011."[91] The Commission did not say that such plants will not be needed at some time, it just said the "Given the deficiencies identified in the IRP analysis, however, we cannot tell when such a plant might be needed."[92]

The Commission went on to say that both natural gas-fired and coal-fired power plants pose significant risks: "fuel price uncertainty and volatility for the gas-fired CCCT and possible CO_2 regulatory costs for the pulverized coal plant."[93] In this context, the Commission stated that the "ability to later add CO_2 sequestration" makes IGCC an "attractive option."[94] It further required PacifiCorp to "fully explore whether delaying a commitment to coal until IGCC technology is further commercialized is a reasonable course

[87] Order No. 06-446 at page 2.
[88] Ibid., at page 9.
[89] Order No. 07-018 at page 1.
[90] Order No. 06-029 at pages 60 and 61, and at page 50.
[91] Ibid., at page 50.
[92] Ibid., at page 50.
[93] Ibid., at page 50.
[94] Ibid., at page 50.

of action."[95] The Commission stated "We believe it may be possible to do so within the RFP process by providing flexibility for bidders regarding on-line date, contract length, resource type and technology."[96]

In the 2007 Order denying the request for RFP approval, the Commission agreed with the Commission's Staff view that the resource need is much lower than that in the 2012 RFP. Instead of 808 MW in 2012 and 1,109 MW in 2013, the Commission found that the need was 157 MW in 2012 and 335 MW in 2013.[97] Further, rather than being a base load need, the Commission agreed with Staff that the need was "limited to the summer on-peak hours."[98] The Utah Commission also has ruled on the level and nature of need, concluding that 1,700 MW of baseload resource are needed. Table VIII-ONE below lays out the three views from PacifiCorp, the Oregon Commission, and the Utah Commission.

TABLE VIII-ONE

Estimates of Level and
Nature of Need

Year	PacifiCorp*	Oregon Commission**	Utah Commission***
2012	808 MW	157 MW	N.A.
2013	1,109 MW	335 MW	1,700 MW
Nature	Baseload	Peaking	Baseload

* PacifiCorp – November 1, 2006 Draft RFP p. 6.

** UM1208 – Order No. 07-018 "Disposition: Request for Approval of Draft RFP Denied" 1/16/07. p. 5, referring to Staff's Reply Comments on PacifiCorp's revised RFP. 11/19/06. p. 4.

***Utah PSC Docket No. 05-035-47. "PacifiCorp 2012 RFP Suggested Modifications." 12/21/06. This excludes 700 MW of planned Front Office Transactions; uses 15% planning margin.

The Oregon Commission raised other specific issues with the 2012 RFP. The following excerpts from the Commission Order illustrate this:

[95] Ibid., at page 51.
[96] Ibid., at page 51.
[97] Order No. 07-018, at page 5.
[98] Ibid.

...PacifiCorp's Draft RFP fails to provide a process to evaluate whether a bridging strategy that delays a commitment to coal until IGCC technology is further commercialized is a preferred course of action.[99]

Before acquiring new thermal base load resources, we expect the company to fully explore conservation, demand response resources[100], renewable resources, distributed resources, and short-term purchases at levels incremental to the amounts in the acknowledged 2004 IRP Action Plan.[101]

We note that competitive bidding may not be the appropriate mechanism to acquire all resources that may be part of the best cost/risk portfolio...Some types of demand response resources also do not lend themselves to competitive bidding.[102]

...[W]e share ICNU's and other parties' concerns about PacifiCorp's ability to sell the surplus energy resulting from new base load resources acquired through the RFP.[103]

...[W]e decline to resolve issues related to CO_2 risk at this time...Further, in Order No. 07-002 (Docket UM 1056), we opened a proceeding to review treatment of CO_2 risk in IRPs.[104]

D. IE RECOMMENDATION

Let us state at the outset that we have not done an independent analysis to address the specific concerns of the Oregon Commission. The issues have already been decided. Our focus here is to mitigate regulatory uncertainty going forward due to differences in views on the level and nature of need.

Again, to its credit, PacifiCorp insulates suppliers from the regulatory uncertainty because there is no regulatory-out clause. However, there is never full insulation so PacifiCorp should mitigate regulatory uncertainty by addressing the Commission's concerns in both its 2006 IRP and the 2012 RFP; regulatory uncertainty may make bidders reluctant to bid aggressively or to bid at all. We have two recommendations to mitigate these effects.

[99] Order No. 07-018 at page 8.
[100] We expect there is untapped potential on the east side of PacifiCorp's system for conservation and demand response measures that would reduce peak summer loads and would be a part of a best cost/risk portfolio.
[101] Order No. 07-018 at page 6.
[102] Ibid.
[103] Ibid.
[104] Ibid., at page 9.

First, PacifiCorp should provide a full IRP analysis showing why and how the three Benchmarks are in the Preferred Portfolio; this would include the full range of PVRR and analysis, all the assumptions which led to the Benchmark's inclusion in the Preferred Portfolio, and a full set of stochastic and scenario planning risk analyses. If a separate analysis must be used to show such a result for the IGCC, then that separate IRP analysis must be provided in full.

In addition, the 2006 IRP analysis should be presented to prospective bidders. Providing the IRP analysis that led to the three benchmark resources is important because it informs bidders on how their bids will be evaluated and on the market, operational, and regulatory circumstances they might be in if they win. Furthermore, it gives a baseline to compete against; it gives at least some indication of how a bidder might beat the benchmarks by offering ratepayers a better deal in terms of price, risk, reliability, and environmental performance. PacifiCorp should offer to conduct a Pre-Bid Conference for bidders on these IRP analyses. This IRP analysis should be distributed as part of the RFP package.

Second, the evaluation phase of the 2012 RFP should be designed to answer the Commission's questions. For example, the Commission asked about the benefits of waiting for the IGCC technology to mature. It should be made clear to bidders that IGCC bids may schedule an on-line date for the IGCC unit later than 2012-2014, if the bidders take responsibility for the cost of purchases or other actions to accommodate the delay. PacifiCorp should emphasize all other accommodations for IGCC bids, too. For example, IGCC is its own category for purposes of the Initial Shortlist; PacifiCorp should state that this means some IGCC bids will make it through to the next steps of evaluation. In addition, IGCC proposals are permitted to bid through a variety of transaction types – PPA, tolling, or asset sale. Further, performing the full CO_2 regulatory analysis, as we recommend above, should allow IGCC to demonstrate any advantages in this regard.

PacifiCorp should also use the 2012 RFP to inform the IRP and, thereby, further address the Commission's questions. For example, the Commission raises the issue of base load versus seasonal peak need. One approach is for PacifiCorp to solicit offers for seasonal sales and/or peaking plants in the 2012 RFP for a term of 5 years or more; the RFP would then inform the IRP in the sense of getting market quotes on price and performance.

Whether PacifiCorp solicits such offers or not, it should, as part of its evaluation, create a portfolio with a seasonal purchase or new peaking plant, and show how it compares to the preferred portfolio(s).

Similarly, as part of the evaluation process, PacifiCorp should create portfolios with additional renewables, DSM distributed generation, and short-term purchases and compare the price and risk to the preferred portfolio(s). The price and performance for these other resources should come from this or other RFPs to the greatest reasonable extent. For example, one of the reasons the Utah Commission found a short-term need for 1,700 MW is that 700 MW of front office transactions (FOT) were put aside in favor of newly solicited resources. PacifiCorp should compare a portfolio with the FOT to the preferred portfolio.

To some extent, these added analyses in evaluation pursue the goal that the RFP informs the IRP – confirmation of price and performance is key in this regard. But it is understood that these added analyses make the 2012 RFP a "shadow IRP;" this may not be anyone's preference, but it is necessary to mitigate regulatory risk and, thereby, get the best deal for ratepayers.

Also in this context, we suggest PacifiCorp assess future rate effects (as compared to today's rates) as the Final Shortlist is determined.

IX. PACIFICORP SHOULD SATISFY THE COMMISSION'S COMPETITIVE BIDDING GUIDELINES

One of the three criteria set by the Commission for RFP approval is that the RFP must satisfy the Commission's competitive bidding guidelines. In particular, the Commission requires that the IE address here Guidelines 6 through 11 and Guideline 13. Of these, the Guidelines which are relevant to Part One of this report (evaluation criteria, methods and computer models) include Guidelines 8, 9 and 10d.

A. GUIDELINE 8

Guideline 8 states:

> Benchmark Resource score: The utility must submit a detailed score for any Benchmark Resource, with supporting cost information, to the Commission and IE prior to the opening of bidding. The score should be assigned to the

Benchmark Resource using the same bid scoring and evaluation criteria that will be used to score market bids. Information provided to the Commission and IE must include any transmission arrangements, and all other information necessary to score the Benchmark Resource. If, during the course of the RFP process, the utility, with input from the IE, determines that bidder updates are appropriate, the utility may also update the costs and score for the Benchmark Resource. The IE will review the reasonableness of the score(s) for the Benchmark Resource. The information provided to the Commission and IE will be sealed and held until the bidding in the RFP has concluded.[105]

Satisfaction of Guideline 8 can only be judged at the time bids are open. However, PacifiCorp is on track to satisfy Guideline 8 in the sense that we understand it will submit its benchmarks for scoring. Two specific central requirements of this Guideline are that (a) the "same bid scoring and evaluation criteria" be used to score bids and benchmarks and (b) "all information" including 'transmission arrangements" be provided for the benchmarks.

Our specific concerns are detailed above as to the requirement to use "the same bid scoring evaluation criteria." In sum, our concern is that PacifiCorp needs to fully account for the higher ratepayer risk of any cost-plus ratemaking for the benchmarks.

B. GUIDELINE 9a, b AND c

Guideline 9 states:

Bid Scoring and Evaluation Criteria:

(9a) Selection of an initial short-list of bids should be based on price and non-price factors, and provide resource diversity (e.g., with respect to fuel type and resource duration). The utility should use the initial prices submitted by the bidders to determine each bid's price score. The price score should be calculated as the ratio of the bid's projected total cost per megawatt-hour to forward market prices, using real-levelized or annuity methods. The non-price score should be based on resource characteristics identified in the utility's acknowledged IRP Action Plan (e.g., dispatch flexibility, resource term, portfolio diversity, etc.) and conformance to the standard form contracts attached to the RFP.

(9b) Selection of the final short-list of bids should be based, in part, on the results of modeling the effect of candidate resources on overall system costs and risks. The portfolio modeling and decision criteria used to select the final short-list of bids must be consistent with the modeling and decision

[105] Order 06-446, at page 10.

> criteria used to develop the utility's acknowledged IRP Action Plan. The IE must have full access to the utility's production cost and risk models.
>
> (9c) Consideration of ratings agency debt imputation should be reserved for the selection of the final bids from the initial short-list of bids. The Commission may require the utility to obtain an advisory opinion from a ratings agency to substantiate the utility's analysis and final decisions.[106]

In commenting on an earlier draft RFP with respect to Guideline 9a, we noted that choosing different transaction types does not assure diversity by "fuel type and resource duration" in the Initial Shortlist. PacifiCorp now explicitly includes fuel type as a basis for the Initial Shortlist, so our concern is mitigated. As for resource duration, to its credit, PacifiCorp will use the annuity method, which will allow shorter-term resources to compete for the Initial Shortlist. As discussed above for the Final Shortlist, however, additional evaluations must be done to assure the option value if shorter term offers is assessed.

With respect to Guideline 9b, PacifiCorp will use the same "modeling and decision criteria" used in its IRP work; the information used will be from the 2006 IRP.

With respect to Guideline 9c, to its credit, PacifiCorp will not use "imputed debt" in determination of the Initial nor Final Shortlists.

C. GUIDELINE 10d

Guideline 10d states:

> If the RFP allows affiliate bidding or includes ownership options, the IE will independently score the utility's Benchmark Resource (if any) and all or a sample of the bids to determine whether the selections for the initial and final short-lists are reasonable. In addition, the IE will evaluate the unique risks and advantages associated with the Benchmark Resource (if used), including the regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected for the RFP.[107]

With respect to Guideline 10d, as noted, PacifiCorp has taken the language literally so it is the Oregon IE who will "evaluate the unique risks and advantages" of the regulatory treatment for the benchmarks.

[106] Ibid.
[107] Ibid., at page 12.

Over and above these specific concerns with the Guidelines, we recommend PacifiCorp take steps to address what we discussed above as the Commission's strategic issues.

PART TWO - THE ADEQUACY, ACCURACY AND COMPLETENESS OF ALL SOLICITATION MATERIALS

X. REVIEW OF SPECIFIC GUIDELINES AND ASPECTS OF THE RFP

A. THE COMMISSION'S COMPETITIVE BIDDING GOALS

In Order 06-446, the Commission reviewed its long standing Competitive Bidding Goals and found that those goals had served the needs of the Commission, the States regulated utilities and consumers well, and required only minor modifications to meet the needs created by the adoption of its Competitive Bidding Guidelines. The Goals established are to:

1. Provide the opportunity to minimize long-term energy costs, subject to economic, legal and institutional constraints;

2. Complement Oregon's integrated resource planning process;

3. Not unduly constrain utility management's prerogative to acquire new resources;

4. Be flexible, allowing the contracting parties to negotiate mutually beneficial exchange agreements; and

5. Be understandable and fair.

Based on our experience in other RFPs for long-term power supply, we believe that these Commissions goals are reasonable and attainable in a well-designed and executed RFP. Goal 1 is consistent with traditional regulatory principles and takes into account the utilities responsibility, in developing its power supply portfolio, to balance cost, risk and system reliability. Goals 2 and 3, as we understand them, recognize the dynamic nature of utility planning and require PacifiCorp to develop a RFP that complements and implements the power supply portfolio acknowledged in the IRP, but allows PacifiCorp the flexibility to adjust its portfolio to meet changing needs as they evolve. Goals 4 and 5 can be achieved if the RFP is clear concise unbiased, does not present unreasonable barriers to participation, and is conducted in a manner consistent with the terms and conditions disclosed.

In the following sections we discuss whether the design of PacifiCorp's 2012 RFP is consistent with these goals and where it is not, suggest changes to the design that will, in our opinion, better facilitate achieving those goals.

B. GUIDELINE 6: RFP Design

Guideline 6 states:

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

As part of our assessment of the draft RFP, we reviewed the Draft RFP and each of its attachments and appendices to assess the overall design of this RFP process with respect to compliance with Guideline 6. As part of our evaluation, we reviewed the reports submitted by the Utah IE to evaluate PacifiCorp's responses to the recommendations made in those submissions. Finally, we reviewed the Final RFP approved by the Utah Commission.

PacifiCorp drafted and provided to all of the parties in its most recent general rate case, RFP and IRP proceedings a copy of its Draft 2012 RFP. The utility conducted the required stakeholder meetings and submitted its Draft RFP for Commission approval. The Draft RFP clearly sets forth the capacity and energy products the Company seeks and the minimum resource size it will accept. It permits smaller QFs to bid in accordance with the requirements of this guideline. It sets out bidder qualification requirements for credit and capability. The filed Draft also describes PacifiCorp's bid evaluation and scoring criteria. PacifiCorp has conferred with the Oregon IE as required. Because the IE was retained after PacifiCorp filed its Draft RFP those discussions are not reflected in the Draft submitted in Oregon. As noted previously, several of the recommendations have been incorporated into the Final RFP PacifiCorp will utilize to conduct this RFP.

As noted elsewhere in this report, we have several remaining concerns regarding various aspects of this RFP, notably product specifications and certain contract provisions regarding Credit and Security issues. Each of these concerns and our suggested changes to the RFP to resolve these concerns are discussed in full later in this report. In general however, we believe the RFP complies with the requirements of Guideline 6. With incorporation of several of the suggested changes noted in this Report we believe the RFP has been improved but remain concerned that in the absence of bids for seasonal and peaking capacity in lieu of base load resources for a portion of the capacity sought in this RFP, PacifiCorp will be challenged in presenting this as a defensible solicitation.

C. GUIDELINE 7: RFP Approval and Issues Raised by the Parties in the UM 1208

> Guideline 7: RFP Approval: The Commission will solicit public comment on the utility's final draft RFP, including the proposed minimum bidder requirements and bid scoring and evaluation criteria. Public comment and Commission review would focus on (1) the alignment of the utility's RFP with its acknowledged IRP; (2) whether the RFP satisfies the Commission's competitive bidding guidelines; and (3) the overall fairness of the utility's proposed bidding process. After reviewing the RFP and the public comments, the Commission may approve the RFP with any conditions and modifications deemed necessary. The Commission may consider the impact of multi-state regulation, including requirements imposed by other states for the RFP process. The Commission will target a decision within 60 days after the filing of the final draft RFP, unless the utility requests a longer review period when it submits the final draft RFP for approval.

We found the process used by the Commission Staff and PacifiCorp to ensure the public had sufficient opportunities to provide comments to be appropriate. All questions posed by stakeholders were at least addressed.

Public scrutiny and review of the draft RFP documents is important in assuring the acceptability of the results achieved when conducting a solicitation of this type. This process contributes to building confidence in the fairness of the RFP process, which is critical to attracting active participation by bidders. Comments from bidders are of particular interest when those comments identify concerns that would deter full participation.

Prior to the employment of the Oregon IE, PacifiCorp held a number of Technical, Bidder and Stakeholder meetings. Those meetings addressed the design of the RFP. The Oregon IE did not participate in those meetings but has reviewed the presentation materials provided. Subsequent to our retention, the Commission Staff, PacifiCorp and the IE participated in two additional meetings with stakeholders. Notices of the meeting were posted on the PacifiCorp web site and participants were notified by email that the sessions would be held. Adequate advance notice of the date and location of each meeting was provided. During these sessions, stakeholders identified concerns and questions about the process and draft provisions. All concerns were fully discussed among the stakeholders, PacifiCorp, the Commission Staff and IE.

The stakeholders raised a number of issues during the first stakeholders meeting that were either addressed by PacifiCorp, or recognized as being before the Commission in other proceedings. A chart summarizing the issues raised is presented in Attachment A.

The second stakeholders meeting was held on Jan. 31, 2007, after the Commission declined to certify PacifiCorp's RFP process, as discussed above.[108] Participant questions at this meeting were focused on whether the solicitation would be conducted, and the procedures PacifiCorp would use to determine whether to execute a contract in the absence of Commission approval of the RFP. In both stakeholder meetings, PacifiCorp participated in a full range of discussions. Even when the utility believed the discussion of a question would not result in the improvement of the RFP process, no attempt was made to limit the scope of discussion.

D. GUIDELINE 10: Utility and IE Roles

The Commission guidelines establish responsibilities for the Utility and the IE.

> Guideline 10: Utility and IE Roes in the RFP Process:
> a. The utility will conduct the RFP process, score the bids, select the initial and final short-list, and undertake negotiations with bidders.
> b. The IE will oversee the RFP process to ensure that it is conducted fairly and properly.

[108] Oregon IE presentation slides from this meeting can be found in Attachment B and Attachment C.

PacifiCorp designed the RFP process in conformity with the Commission's guidelines, respecting the role of the IE and the responsibilities of the utility. Our assessment of PacifiCorp's success in completing these responsibilities will, by necessity, come only after bids are received and evaluated.

The Company participated in numerous meetings with the IE to assist in our understanding of the RFP process. During these meetings PacifiCorp considered, but did not necessarily accept, all of the concerns and suggestions we offered.

PacifiCorp provided the information that is critical to our assessment of the design of the RFP process, including information regarding the design and management of the company's code of conduct. The design and sufficiency of the code of conduct design and implementation was identified as a significant concern of bidders, the Commission Staff, and the IE. We are also aware that FERC has a continuing interest in ensuring a complete separation of transmission functions from other aspects of PacifiCorp's operation.

PacifiCorp designed the RFP to meet the Guideline 10 requirements in two specific areas: Code of Conduct compliance, and Communications Protocols.

Code of Conduct

We believe it is imperative that bidders have complete confidence in the fairness of the RFP process, before bids are submitted. Lacking this confidence, we believe the quality and quantity of bids will be adversely affected. A strict code of conduct is important, regardless of whether affiliates of the utility will be participating. All bidders, regardless of their relationship with the utility, should have access to the same information at the same time, and there should be no private discussions between prospective bidders and the company.

PacifiCorp provided its Code of conduct as Attachment 20 to the draft RFP. The Company supplemented this information with organization charts detailing the separation of personnel. Also, the Company provided a memorandum dated February 26, 2007, in which an Assistant General Counsel provided specific direction to those PacifiCorp personnel who will be involved in the RFP process on Code of Conduct compliance requirements.

Attachment 20 is detailed and thorough and, if adhered to, will provide the structure for a solicitation that is free of unauthorized contact between the Evaluation Team and any prospective bidder. By including the Code of Conduct as part of the RFP, the Company puts all participants, and not PacifiCorp personnel alone, on notice of the conduct expected of all parties.

The Code of Conduct expressly prohibits the IRP work group from sharing transmission system information with either the Evaluation Team or the Benchmark Team. Also, the Code of Conduct prohibits Evaluation Team members from having "contact or communication with any Bidder other than through the IE's."[109]

PacifiCorp's Code of Conduct details the separation of the Evaluation Team into seven separate work groups and provides for the further separation of certain individuals before the final shortlist is selected. The so-called "blinded" work groups will include the Origination, Structuring and Pricing, Transmission Mangier and Environmental groups. The individuals in each of these groups will be identified to the IE when the RFP is issued in final form.[110]

Attachment 20 acknowledges the existence of shared services personnel, and asserts the structure employed by PacifiCorp will comply with the FERC Standards of Conduct requirements for shared services. Similarly, the February 26, 2007, memorandum reminds PacifiCorp personnel of the obligation to "abide by FERC's Standards of Conduct." We believe that by recognizing the FERC standards, the Company will take those actions it believes are appropriate to comply. However, the IE offers no opinion on whether FERC will find those actions sufficient.

In the February 26, 2007, memorandum, PacifiCorp committed to schedule Code of conduct training. No date is identified for completion of the training.

We believe PacifiCorp's Attachment 20 to the RFP sufficiently describes the roles and responsibilities of the functional groups that will participate in the RFP. We also believe

[109] Attachment 20 at 1.

[110] PacifiCorp provided the IE with a list of personnel who will complete Code of Conduct training, without designating which will be assigned to the "blinded" work groups.

PacifiCorp has accurately identified the need to separate transmission functions, the Benchmark Team, the IRP team, and the Evaluation Team. PacifiCorp's decision to segregate the "blinded" groups only after selection of the Initial Shortlist may prove to be sufficient separation, but we would prefer total separation beginning with the issuance of the RFP. While we believe that, in fact, the timing of this separation may prove effective, this structure seems to needlessly invite future questioning, or challenge, regarding the evaluation process prior to the selection of the shortlist.

We anticipate that PacifiCorp will provide the Code of Conduct training materials, and certification of completion of the training by each individual who the Company believes should complete the training. Similarly, we anticipate that the training materials will include procedures for documenting any unauthorized contact by a bidder, and the procedures that will be used to notify the IE of any deviation from the established procedures. This last point is of interest, for we have found that violations of Code of Conduct requirements are most likely to be the result of inappropriate contact initiated by a bidder. We are prepared to act, in coordination with PacifiCorp and the Commission Staff, should any bidder cause a violation of the Code of Conduct, and expect PacifiCorp will establish protocols for a timely notification of the IE of any violation, regardless of the source.

Communication Protocols

Attachment 4 to the draft RFP sets for the Communications Protocols PacifiCorp proposes using for the RFP. The protocols address three aspects of the RFP; the role of the IE, communications between the IE, the Company and bidders, and communications between the Evaluation Team and the Benchmark Team.

The role and functions of the IE set forth in the Communications Protocols are consistent with the goals of the Commission's solicitation rules. They are also similar, and in many ways identical to the IE functions in other jurisdictions in which we serve as Independent Evaluator or Independent Monitor for wholesale power supply solicitations. However, we have some concerns as to how these functions are applied to the PacifiCorp RFP.

The protocols call for the IE to receive and "blind" bid responses. In our experience, blinding bids is effective with an auction, particularly for short-term purchases where the auction is reduced to price-only determinations, before bids are submitted. With an RFP for a long-term supply, "blinding" is an illusion, at best. For example, the location and identity of each generating facility must be disclosed in order for the company to determine reliability and deliverability. Removing the name of the bidder does little to disguise the source of the bid. As we understand the Commission rules, the "blind bid" protocol is required, and we will make best efforts to comply. At the same time, bidders, the Commission, and PacifiCorp should accept that it is unlikely the identity of each bidder will be a mystery to the Company.

In the area of communications involving the bidders and the Company, the IE will review all questions posed by bidders through the web site, and responses provided by the Company. Under the protocols, we will be responsible for redacting competitive information from both questions and responses. Because a different company maintains the web site, the procedures for our access to the questions, and the protocols for review, redacting as necessary, and posting of questions and responses have yet to be completed.

Regarding communications between the Evaluation Team and the Benchmark Team, the protocols and separation designed by PacifiCorp, if adhered to, will provide for complete separation of the two teams. The Communication Protocols provide that PacifiCorp will deliver the names of each person who will be a member of the Evaluation Team and the Benchmark Team when the RFP is provided. This is appropriate, and we suggest PacifiCorp also post a listing on the web site of the names of the individuals serving on each team. This will serve to put bidders on notice of the PacifiCorp personnel with whom discussions of the RFP should not occur outside of the Communications Protocols. We have found such full disclosure to be helpful in avoiding inadvertent violations of standards of conduct and codes of conduct. We encourage PacifiCorp to post the names of all team members, along with which team they serve, including those personnel who will be designated as "blinded" participants.

E. GUIDELINE 11: CLOSING REPORT

Guideline 11: IE Closing Report: The IE will prepare a closing report for the Commission after the utility has selected the final short list. In addition, the IE will make any detailed bid scoring and evaluation results available to the utility, Commission staff and non-bidding parties under protective orders that limit use of the information to the RFP docket subject to the terms of a protective order.

We will prepare a closing report and make results available to utility after the RFP process is completed. The RFP process designed by PacifiCorp respects the role of the IE and provides sufficient time for the completion of the closing report. Based on our discussion to date, we believe PacifiCorp will make available to the IE all of the information we will need to complete our closing report in a timely manner and with all of the detail the Commission expects.

F. GUIDELINE 13 – RFP Acknowledgment

Guideline 13 states:

> The utility may request that the Commission acknowledge the utility's selection of the final short-list of RFP resources. The IE will participate in the RFP acknowledgment proceeding. Acknowledgment has the same meaning as assigned to that term in Commission Order No. 89-507. RFP acknowledgment will have the same legal force and effect as IRP acknowledgment in any future cost recovery proceeding. The utility's request should discuss the consistency of the final short-list with the company's acknowledged IRP Action Plan.

Based on discussions we have held with the Company, we are unable to assess whether the Company will seek Acknowledgement of the resources it selects, in any are selected, as a result of this RFP. In the event PacifiCorp requests Commission acknowledgement of its selections, the IE will be available to participate in acknowledgment proceedings.

XI. ASSESSMENT OF PROCESS INTEGRITY ISSUES

RFP Design

PacifiCorp has determined that it needs to add baseload generation by 2012 to meet its system needs and to maintain the reliability of the PacifiCorp system. Accordingly, it developed its RFP to meet that need. We take as a given, that the Commission has rejected this RFP and determined that PacifiCorp may not require the baseload generation it is seeking and that the RFP as drafted does not align with PacifiCorp's most recently acknowledged IRP. The RFP, therefore, violates Commission Guideline 7.

However, it is structured in a manner that can be used to conduct a fair and transparent solicitation possibly satisfying the Commission's established Goals, if the RFP is amended to address the issues identified in this Report. These amendments would allow the Company to assess the value of acquiring non-baseload resources as a means of addressing the Commissions concerns and mitigating some of the risk inherent in the market today, most notably the environmental risks that are being widely discussed at both the State and Federal levels.

Recommendation 1: The Commission Goals recognize that the RFP is to "Complement Oregon's integrated resource planning process" and "Not unduly constrain utility management's prerogative to acquire new Resources". We therefore recommended to the Company that the RFP be amended to solicit for seasonal and peaking resources for terms of five years or more in addition to the products currently being sought. By permitting non-baseload resources to participate in this RFP, the Company would have an opportunity to assess the role such resources could play in its portfolio and a better basis on which to support its decisions. While this may impose on the Company additional work in conducting the RFP, it would be in a position to select the appropriate resources to meet the needs of Oregon consumers that it determines are needed. With the additional information made available the Company would also be better positioned to support its selections.

PacifiCorp has chosen not to accept this recommendation and in its Final and approved RFP does not provide bidders with an opportunity to submit bids for other than baseload resources.

Recommendation 2: We are also recommending that the Company permit Bidders to submit bids that toll both fuel and fuel transportation, for bids of ten or more years. Tolling of fuel transportation is not uncommon in RFPs of this type. Typically Merchant producers seek to allocate all risks related to fuels to the Buyer, particularly when Buyer has dispatch rights and control. Absent such tolling Merchants in their pricing will seek a premium for accepting that risk. Tolling transportation is also consistent with the Buyer's responsibility for providing the fuel. We have restricted this recommendation to longer-term bids to allow the Company to align its exposure to contracts for firm transportation to the term of the underlying PPAs. We are aware that many pipelines are unwilling at this time to enter into short-term firm transportation contracts.

PacifiCorp has amended its Final RFP to accept the Oregon IE's recommendation in part and to allow Bidders to propose that PacifiCorp toll the transportation of natural gas. Bidders will however be required to demonstrate that adequate transportation is available from identified sources. PacifiCorp has decided that it will not toll coal transportation due to the complexity and volatility of such transportation services. We believe that the Company's decision improves the RFP process and that its decision to not toll coal transportation does not render the RFP biased or invalid.

Recommendation 3: Additionally, as discussed in Part One of this Report, we believe that the bid and Benchmark Resource evaluation process needs to be enhanced to address the concerns noted. To the extent that those suggested changes to the evaluation methodology are adopted, they should be disclosed in the RFP.

Recommendation 4: The RFP should clearly state that IGCC resources may be bid, and will be evaluated, like any other resource. In particular, the ability of a marketer to bid an IGCC unit with an in service date of 2012, 2013 or 2014, should be clarified to eliminate any confusion regarding the responsibility of the marketer to provide interim service during any of the years not bid. Without clarification, the RFP could be read to restrict bids from IGCC facilities as only acceptable if the facility is fully operational in 2012. Based on discussions we have had with the Company we believe PacifiCorp intends to require IGCC facilities to meet operational in-service dates that are applicable to other, more established, generating technologies.

XII. RFP DOCUMENTATION

The RFP

On November 1, 2006, PacifiCorp submitted for Commission approval, it's Draft RFP. That draft described in detail the power supply products sought by the company, the processes for conducting the RFP the Company intended to use and the methods that would be used to evaluate the bids received. The Draft RFP also set out requirements bidders would need to demonstrate in order to be considered. Those included bidder technical qualifications and minimum creditworthiness standards. The Draft RFP contained discussions of the RFP's proposed schedule and protocols for communicating with the Company. In its draft, PacifiCorp discusses each of the critical issues needed to conduct this RFP. Among other things, the Draft included descriptions of the required Bid information, the process by which bids are to be submitted, bid fees, and how the PacifiCorp RFP Team will be organized. As described, PacifiCorp will establish separate Bid Teams to manage the RFP and to prepare the Benchmark bids. These teams will operate pursuant to a Code of Conduct designed to prevent any undue influence on the evaluation team and the inappropriate interchange of information between the Teams.

Subsequent to filing of the draft RFP with the Commission, PacifiCorp resubmitted revised documents to the Utah Commission, which incorporated several of the changes recommended by the Oregon IE. That draft was approved by the Utah Commission on April 4, 2007. We reviewed the materials approved by the Utah Commission and found the RFP document to be comprehensive and clear. We have compared it to other RFP documents we have reviewed and find it to be consistent with the content found in those RFP documents. We also found that PacifiCorp was more open in its disclosures and in the provision of Company data than is usual in the industry. Appended to the RFP, PacifiCorp presented the required submittal forms, Pro Forma Contracts and other pertinent information Bidders will need to prepare responsive bids.

In the following sections we discuss the pertinent attachments and appendices to the Draft RFP. We note that Final RFP attachments and appendices have been amended to conform to the changes, made by the Company, that have been included in the Final RFP.

XIII. THE PRO FORMA CONTRACTS INCLUDED WITH THE RFP

PPA

PacifiCorp has provided as Attachment 3 to its Draft RFP and Final RFP a pro forma Power Purchase Agreement (PPA) that will serve as the basis on which certain transactions in this RFP will be executed. The PPA, according to the Company, is similar to PPAs the Company has previously executed with power suppliers. While the Company intends to utilize the pro forma PPA as the contract it will execute with selected bidders, it recognizes that the PPA will need to be amended to accommodate corporate, operational and financial issues unique to the bids it selects.

The PPA is comprehensive, addressing each of the terms and conditions normally covered in contracts of this type. The PPA can be utilized for each of the generation technologies that may be bid and can be amended to meet the contract needs of bids with differing terms and risk profiles. As drafted, the PPA can be described as Buyer biased. For instance, both the Draft and Final PPA do not require the Company to post security, while requiring even some investment grade bidders or bidders with investment grade guarantors to post security. Such terms are not uncommon in other PPAs we have reviewed, but are typically the subject of negotiation. Similarly, the terms of the pro forma PPA expose bidders to actual damages in the event of a default by bidder. We believe this to be a reasonable and balanced term, but have found that bidders are frequently disinclined to accept such an open-ended liability. In recent RFPs we have observed a preference by bidders for liquidated damages, a term that predetermines the potential damages for which a defaulting party would be liable. PacifiCorp has indicated that as a general rule it will, during negotiations, attempt to preserve the terms and conditions set forth in the pro forma PPA but is prepared to accommodate the legitimate needs of its counter-parties if those PPA amendments do not materially alter the value of the PPA. As a result, we believe that it will be critical to the success of this RFP to closely monitor the Company's evaluation of bidder requested changes to the PPA whether they occur as part of the bids submitted or during negotiations with selected bidders to assure that the evaluated values of bids selected are not materially impacted and to assure that no unwarranted benefit is accorded to any bidder or technology.

The PPA includes adequate provisions for the posting of security, consistent with the terms for security we have observed in similar PPAs.

The PPA describes Force Majeure events and the rights and responsibilities of the parties in the event of a Force Majeure. These are also consistent with industry practice.

Typical of contracts of this type, the Pro Forma PPA delineates the responsibilities of the parties and contains Representations and Warrantees of the parties. It outlines many of the specific operating metrics that will be used in managing the contract over its term. These are to be specified in the bid and incorporated in the PPA during final negotiations.

We believe the Pro Forma PPA is properly drafted and should be used as the basis for negotiating final contracts for service entered into as a result of this RFP.

We have no recommendations regarding the Pro Forma PPA. However, we note that, as explained in Part One of this report, there is no requirement that the Benchmark Resource live up to the same requirements set for bidders in the PPA, including the requirement for credit support.

Tolling Agreement

This Tolling Agreement is a contract pursuant to which PacifiCorp will accept the responsibility to provide to a selected bidder the fuel required to generate the energy to which PacifiCorp is entitled. PacifiCorp will Toll natural gas meeting specifications as set forth in the contract.

The pro forma Tolling Service Agreement attached to the Draft RFP as Attachment 5 is similar to the pro forma PPA, but incorporates terms and conditions necessary to provide the fuel tolling by PacifiCorp. As drafted we believe the Tolling Service Agreement is an appropriate basis on which to negotiate final contracts in this RFP. We do, however, raise the same cautions as we noted in our discussion of the PPA, that changes and amendments to this agreement must be closely monitored to assure that they do not materially alter the value of the bid submitted or unduly advantage any bidder.

If PacifiCorp elects to adopt our recommendation to Toll fuel transportation, this pro forma agreement will require the addition of terms and conditions regarding the rights and responsibilities of the parties. In such case, the IE will monitor the development of the required terms and will report on the revised Tolling Agreement in our subsequent reports.

Asset Purchase & Sale Agreement

PacifiCorp provided comprehensive draft purchase and sale terms, to be incorporated into any contract that would be executed if an asset transfer were to be part of a proposal. We find these documents to be of sufficient detail to advise prospective bidders of the terms and conditions PacifiCorp would expect to be incorporated into a final Asset Purchase and Sale Agreement. Because of the unique nature of the sale of assets in general and real estate in particular, our general review for sufficiency should not be misconstrued as an endorsement of these specific documents. Every asset sale must conform to requirements of the jurisdiction. In our role as IE we have not undertaken such an analysis. At the same time, the basic requirement of full disclosure of expected terms will be met by this draft Agreement, even though the details are to be negotiated at a later date. From the draft RFP documents a prospective bidder would know PacifiCorp's position on all expected terms for a purchase and sale, before submitting a proposal. We note that none of the stakeholders, who we presume to be aware of any unique jurisdictional constraints, commented on the draft Asset Purchase and Sale Agreement, even when invited to do so during the first stakeholder meeting.

Currant Creek Engineering, Construction and Procurement Contract (EPC)

The EPC Contract proposed by the Company requires a bidder proposing to construct a facility on PacifiCorp's Currant Creek site to provide, all of the engineering, construction and procurement services necessary to construct a generating facility of approximately 500 MWs by a guaranteed in service date. It is similar in form and in substance to contracts used in the industry for the purpose of contracting for these services. Typically these services are provided by a single vendor who retains the full responsibility for assuring that the services are coordinated and provided on time, within budget and in a professional and workmanlike manner. This contract is consistent with that approach. It clearly describes the roles of the parties to the contract and contains appropriate provisions, which will allow PacifiCorp to monitor and oversee the construction of the proposed facility. The contract contains adequate security provisions to mitigate the risk of nonperformance by the Contractor. The contract contains terms controlling working arrangements, logistics, project schedule and such other matters as are normally dealt with in similar contracts.

As drafted we believe the EPC contract does not impair the ability of potential bidders to participate in the RFP. As with all other contracts and agreements proposed by the Company, we will monitor the Company's evaluation of changes to this contract and to its decisions during the negotiation of any EPC contracts to assure that the value of any bid is not materially altered through the reallocation of costs or risk.

XIII. SITE PURCHASE AGREEMENTS

PacifiCorp has included in its Draft RFP Site Purchase Agreements for its Currant Creek and Lakeside sites, which will be available for development by potential bidders in this RFP. The IE has not reviewed these documents for legal sufficiency and has no recommendations or observations regarding their conformity with industry practices. In our experience, we have found few instances where a soliciting utility has made its real estate available to third parties for development. We believe that by doing so, PacifiCorp has enhanced the likely success of this RFP.

XIV. CREDIT REQUIREMENTS

PacifiCorp provided in Attachment 21 to the RFP a thorough description of its proposed credit requirements and credit scoring process. Consistent with industry practice, the Company requires Bidders to:

- prequalify prior to bid;
- identify affiliate relationships, if any;
- provide evidence of required credit support; and
- provide evidence of additional credit assurances being offered.

The Company will evaluate the creditworthiness of each Bidder using 5 criteria;

1. Credit Quality of Bidder or Entity providing credit support on behalf of Bidder
2. Type of Eligible Resource
3. Asset-Backed vs. Non- Asset Backed Resource
4. Size of Eligible Resource
5. Date the Resource comes online

Actual credit requirements will be set based on a number of factors. The lower the credit rating of the bidder or entity providing credit support, the higher the value of required credit assurance. Resources that are based on acquisition of an asset by PacifiCorp have a lower value of required credit assurance than other resources. Non-Asset backed resources require higher credit assurance than asset-backed resources. The larger the resource, the higher the value of required credit assurance. And, the later the resource comes online, the higher the value of required credit assurance. PacifiCorp reserves the right to update the credit assurance information of the bidders during the process.

Bidders who are already credit counter parties of PacifiCorp may be subject to additional credit assurance requirements or exclusion from bidding if necessary to protect PacifiCorp from counter party credit concentration risk.

PacifiCorp has set out security requirements that vary with the credit rating of the bidder, the size and type of the asset bid, the term of the offer and the expected energy

Party Guarantees. Security is to be provided on a sliding schedule from the effective date of the contract until the commencement of service.

All counter parties have the opportunity to meet established credit requirements regardless of the Bidders credit rating. More highly creditworthy Bidders may not need to provide security while less creditworthy parties may need to post security for any size bid of any duration. Each Bidder's credit requirement will be evaluated based on information provided by the Bidder in the Request for Qualifications portion of the RFP and will be based on submitted financial information.

The dollar amount of credit to be provided will be determined based on PacifiCorp developed estimates of replacement costs, essentially a mark to market basis augmented by a risk factor. PacifiCorp's credit and security requirements were described to Bidders and set out in tabular form at a workshop PacifiCorp conducted on Sept. 21, 2006 these requirements are similar to requirements we have observed in other RFP's conducted recently.

In a recently completed RFP for firm power, conducted by Georgia Power Co., the following security requirements were approved by the Georgia Public Service Commission:

Applicable Dates	Eligible Collateral ($/kW)
Agreement execution through Threshold Date	75
From the Threshold Date through the earlier to occur of the RCOD and Commercial Operation Date	120
From the earlier to occur of the RCOD and the Commercial Operation Date through the Term of the Agreement	Annual Period 1-5: 380 Annual Period 6-10: 325 Annual Period 11-15: 270 Annual Period 16-20: 215 Annual Period 21-25: 155 Annual Period 26-30: 90

Alternatively, Arizona Public Service typically used a methodology for establishing credit support based on an estimate of the replacement cost of power as periodically determined by APS. Parties to PPAs with APS have the right to request independent third party quotes if they challenge APS' calculations. Credit requirements for APS vary over time as support levels are adjusted to reflect current market conditions. Although this method differs from that used by PacifiCorp, it results in levels of support roughly comparable to those established by PacifiCorp.

In auctions conducted in New Jersey and Illinois the soliciting utilities established the credit support requirements using a "mark to market" methodology. Bidders were provided with an "unsecured line of credit" that varied between $0 and $60,000,000 in New Jersey and up to $80,000,000 for one utility in Illinois, based on the bidder's credit rating. More financially secure counter parties were offered the larger credit lines. This approach is similar to the approach employed in Arizona. It also corresponds to PacifiCorp's schedule of required security as described in its Attachment 21.

PacifiCorp will also require counter parties to provide to PacifiCorp a perfected subordinated security interest in all of the real property associated with the resource used to provide the service contracted for. According to PacifiCorp, such terms are in general use in contracts it has negotiated with energy providers. In our experience such terms are not generally required in RFPs being conducted in the industry. We recognize the intent is to provide an additional layer of security for PacifiCorp and its customers but we are concerned that such a requirement may both complicate Sellers ability to contract and may discourage some bids. We will carefully monitor the concerns, questions and comments made by potential bidders and if appropriate recommend that PacifiCorp reconsider this requirement.

PacifiCorp has structured the security requirements in a manner that will allow all parties to participate. While creditworthy counter-parties are advantaged by this approach PacifiCorp has appropriately imposed obligations on less creditworthy parties in an effort to mitigate the risk to Oregon consumers and its shareholders of operational or economic defaults. While these terms may create a barrier to participation by under-funded or financially weaker bidders, we believe PacifiCorp has struck an appropriate balance.

The above requirements appear to be reasonable and consistent with good industry practice. The assumptions used in establishing the values in the credit matrix will be tested for reasonableness and consistency with similar assumptions used by PacifiCorp in its other financial planning and risk management activities.

XV. OPTIONS TO EXTEND ACCELERATE OR DELAY

In order to encourage bidders to provide to the Company bids containing some degree of flexibility thus allowing the Company to better manage the introduction of new capacity and to tailor it's portfolio to its load, the Company has requested that Bidders specify the terms and conditions under which bids can be extended, accelerated or delayed. Once accepted, the Company shall have the right to exercise those terms if it so chooses. This approach is well developed and will allow Bidders to submit that are more valuable to PacifiCorp's customers. All options bid will be evaluated and to the extent that PacifiCorp determines the value of the option such value will be used in the selection of bids to be short-listed. Allowing Bidders to submit options of this type in our opinion a good practice and PacifiCorp's decision to incorporate such terms has enhanced the probable success of this RFP.

XVI. BID FEES

PacifiCorp has determined that bid fees of $10,000 per bid will be required from most categories of "Eligible Resources", to offset the cost to the Company of conducting this RFP. That bid fee permits the Bidder to submit one base bid and up to two alternative bids from the same resource. Additional alternative bids may be submitted for a fee of $1000 each. The Company has also indicated that Bidders may provide multiple bids from different resources, but such bids will be considered as separate and will require bidders to pay a bid fee of $10,000. Bids from QFs or for Load Curtailment will only be assessed a bid fee of $1000.

These bid fees are commensurate with bid fees typically charged in RFPs of this type. We see no reason why these fees should impair the ability of qualified bidders to participate in the RFP.

XVII. OTHER SUPPPORTING INFORMATION

PacifiCorp's RFP, PPA and other contract drafts are supported by and incorporate attachments and appendices that disclose to bidders information that will be required to prepare a responsive bid. Many are documents that must be submitted. Others clearly describe PacifiCorp's assumptions regarding contract related costs and qualification requirements. Taken as a whole the information presented is adequate and in many regards exceeds the level of disclosure we normally see in RFPs of this type. While some of PacifiCorp's assumptions and requirements may not be consistent with what bidders may hope for, they are clear and within the norms of assumptions and requirements we have observed in other RFPs.

We do believe that one requirement of Appendix E, the Officer Certification Form, to be unrealistic and, potentially, a deterrent to participation by bidders. PacifiCorp would have the bidder commit that the "This proposal is firm and will remain in effect until the later of May ____, 2008 or that date which is 300 days after the proposal due date provided in the RFP, as such due date may be extended from time to time by PacifiCorp." This provision makes no recognition that a bidder may not be included in the shortlist, and, as drafted, provides PacifiCorp with complete discretion on determining how long the bid must remain open. In effect, PacifiCorp is requiring a free option from each bidder, regardless of how attractive their bid may be. We will not opine on whether PacifiCorp could enforce this provision, but we know from experience that in other jurisdictions bidders find such a long term option to be problematic. We have found that bidders are reluctant to present the same assets to multiple buyers, and they are generally unwilling to execute commitments, knowing they may need to negate them. We believe it would be more appropriate for PacifiCorp to release all bids that are not short-listed on the date the short-list is established. Also, we believe it would be appropriate for PacifiCorp to make the extension of the proposal due date to be determined with the agreement of those bidders who are counter-parties to a PPA.

Review of the Adequacy, Accuracy and Completeness of All Solicitation Materials

As noted in our previous discussions, PacifiCorp has assembled a comprehensive set of RFP materials and has provided them to the Stakeholders, Commissions and potential bidders in a timely manner. There has been ample opportunity for all interested parties to review and comment on the filed documentation and proposed processes. As noted, we have not observed any instance in which the RFP documentation is inadequate, inaccurate or incomplete. We do have concerns, as noted, about whether decisions made by the Company in this RFP can be accurate in the absence of bids for non-baseload resources and whether the evaluation processes can be appropriately completed.

Consistency With Accepted Industry Standards and Practices

PacifiCorp has developed an RFP that is consistent with RFP processes and procedures used by other utilities seeking long-term power supply contracts. It is however, more expansive in its product requests than most others we have reviewed. Typically, utilities will not seek bids for asset acquisition and sales. According to PacifiCorp, it has uniquely tailored this RFP to meet the requirements of its regulatory environment and the specific issues facing western utilities. On balance the RFP appears to be slightly biased in favor of the Buyer. This is usually the nature of draft RFPs and should not impede participation by qualified bidders. The terms and conditions detailed in the RFP fall within the range of terms we have reviewed in other RFPs, as are the Pro Forma contracts included in the RFP documentation.

Attachment A

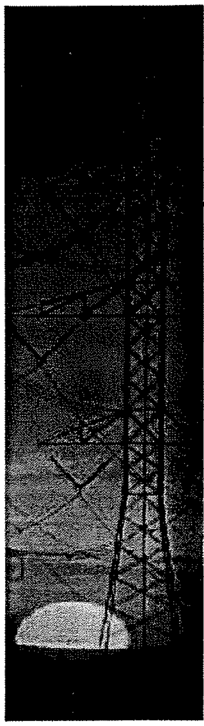
Subject Area	*Comment Summary*	Discussion Points (# refers to comment summary list)
RFP STRUCTURE	1. Consistency of evaluation process (Bids vs. Benchmarks) 2. Does process encourage bids for IGCC facilities 3. Should evaluate top-performing portfolios at 12% and 15% planning margins (including bridging strategies for east side of system) 4. Does the RFP unfairly favor the Benchmarks by imposing the need for fixed price bids to include a risk premium to cover variable costs that the Benchmarks will recover from ratepayers in future rate adjustments 5. Should the PPA be made partially cost-plus to offset this favoritism as suggested by the Utah IE 6. Should bidders be asked to offer (and price) flexibility into their project timelines 7. Is there sufficient separation between the Benchmark Team and the Bid Evaluation Team 8. Should there be Code of Conduct changes to assure adequate separation 9. Does the RFP favor an APSA (Asset Purchase and Sale Agreement) over a PPA because the risk to the supplier under a PPA is higher as noted by the Utah IE 10. Should the cost of possible greenhouse gas regulation be imputed in bid evaluation to all bidders? Or should a bidder be allowed to assume the risk of complying with such regulations 11. Are credit and security requirements appropriate <u>PENDING BEFORE COMMISSION</u> 1. RFP not aligned and/or inconsistent with IRP a) Capacity need (MWs, Base vs. Peaking, Fuel) b) Bridging Strategy c) Planned removal of 700 MW from 2004 Action Plan on east side of system 2. Should permit on-peak summer month bids on east side of system 3. DSM modeling is questioned.	1. Items 1, 4 & 5 are interrelated. RFP process & evaluation should be unbiased re generation, fuel and ownership. 2. RFP should be unbiased as to type of generation. Should there be other IGCC options allowed, including construction on PacifiCorp sites? 3. Should 12%, 15%, or both be used for RFP? 6. IE to review whether RFP provides sufficient flexibility. 7. 7 & 8 are interrelated. IE to review sufficiency of Code of Conduct 9. IE will review risk assignment. 10. Should bidders be allowed to submit bids in which seller assumes this risk? 11. IE should review PacifiCorp's "credit matrix" to evaluate its appropriateness. 1. RFP is not a substitute for the IRP process. Guidelines do not preclude differences between IRP and RFP. 3. The DSM component should be addressed in an IRP docket.

Subject Area	*Comment Summary*	Discussion Points (# refers to comment summary list)
PROCESS	1. Timing assumptions re permitting 2. Values assigned to criteria are in question, e.g., a) CO_2 adder b) Renewable capacity credits c) Sequestration d) Diversity risk 3. Evaluation of acquiring resources that target summer on-peak hours (R/T base load resource) should be included 4. Bridging strategies for east side of system needed e) Renewable resources incremental to 1,400 MW by 2015 commitment f) Short-term market purchases incremental to commitment to 2004 IRP g) Incremental conversion & DSM targeting summer on-peak need h) Other market bids targeting summer on-peak hours ~~5. Credit scoring needs adjustment~~[111] 6. Other inputs need refinement 7. Operational evaluation needs refinement a) Ramping b) Minimum load <u>PENDING BEFORE COMMISSION</u> 1. Calculation of resource need inconsistent with recent avoided cost filings 2. Should imputed debt be included in the bid evaluation	1. Is there a bias in favor of the benchmark included in the evaluation model? 3. This is pending before the Commission. Diversity should be viewed on a system-wide basis, ergo, this is an IRP issue. 4. Should least cost vs. least risk assessment be included in evaluation? Should evaluation include cost of bridging vs. value of option? 1,400 MW of renewable resources is included in the IRP modeling. Should bridging be included in evaluation? If so, how many years of bridging should be considered included? 5. PacifiCorp will not do credit scoring. Credit is a pre-qualification criteria. IE to review credit & security requirements for reasonableness & consistency with industry standard? 6. Value of surplus power may be impaired (ala, CA) should it be included in evaluation. Are evaluation criteria (price and non-price) appropriate, e.g., weighting of data points? 7. Include all points noted by Utah IE. 2. Imputed debt is not in evaluation model. Will be addressed in cost recovery phase.

[111] This issue to be reviewed with the issue identified as #11 in the "RFP Structure" section on page 1.

Subject Area	*Comment Summary*	Discussion Points (# refers to comment summary list)
ENVIRONM'L	1. CO_2 risk 2. Carbon Sequestration 3. Value and timing of carbon reduction strategy for coal	1. IE will identify policy choices and issues that will address CO_2 risk, etc., but are beyond scope of the RFP. E.g., emission policy, Cap & Trade, generation performance standards. I.e., what needs to be addressed by public policy officials. 2. Items 2 & 3: IE will review trigger analysis and scenario planning. Description of evaluation modeling to be included in IE report.
COAL GENERATION	1. CO_2 risk 2. Cost vs. risk not sufficiently developed 3. CO_2 regulatory costs should be included (as per 2004 IRP) in order to establish difference B/T pulverized coal plant & IGCC plant. <u>PENDING BEFORE COMMISSION</u> 1. PacifiCorp has not demonstrated need to acquire more than one new Thermal resource	These items were addressed in discussion of environmental issues. 1. Items 1 & 2: Least cost vs. least risk is a policy decision that must be proven by PacifiCorp. 2. Quantifying the value of CO_2 adder is reviewed every two years in IRP process.
RENEWABLE SOURCES	1. Is PacifiCorp acquiring all available cost effective conservation opportunities? (level, timing, etc.) <u>PENDING BEFORE COMMISSION</u> 1. Value of capacity credits	1. This RFP is designed to meet only a slice of system need and not all needs or consider all sources. Balance of need and bridging strategy should be defined.

Attachment B

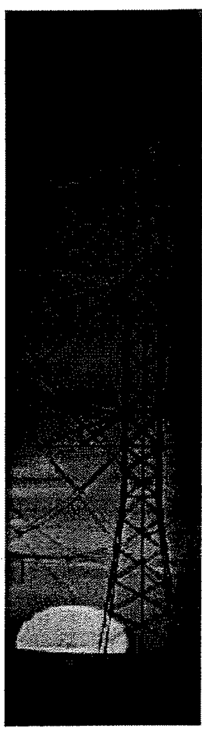


PRELIMINARY THOUGHTS ON BID AND BENCHMARK EVALUATION METHODS IN PACIFICORP'S 2012 RFP

PREPARED TO AID DISCUSSION
IN THE SECOND STAKEHOLDER MEETING

PREPARED BY:
BOSTON PACIFIC COMPANY, INC.

JANUARY 31, 2007



OUTLINE

I. TO ASSURE THE BEST DEAL FOR RATEPAYERS, THE METHODS FOR BID AND BENCHMARK EVALUATION MUST BE FAIR AND TRANSPARENT

II. ALIGNMENT OF THE RFP WITH AN ACKNOWLEDGED IRP

III. RATEPAYER RISK ACROSS TRANSACTION TYPES

IV. RATEPAYER RISK ACROSS TECHNOLOGY TYPES

2

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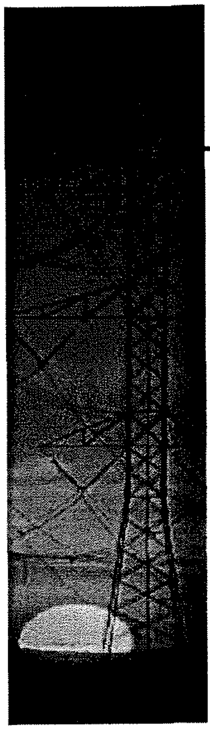

OUTLINE

V. THE RISK OF FUTURE CO_2 REGULATION

VI. IMPUTED DEBT

VII. NETWORK RESOURCE STATUS

VIII. DETAILED ANALYTICAL TECHNIQUES EMBEDDED IN MODELS

IX. STAKEHOLDER FEEDBACK

3

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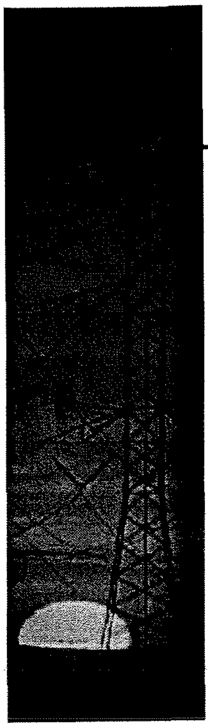

I. TO ASSURE THE BEST DEAL FOR RATEPAYERS, THE METHODS FOR BID AND BENCHMARK EVALUATION MUST BE FAIR AND TRANSPARENT

A. Why Fair and Transparent?

1. Attracts bidders
2. Promotes aggressive bidding
3. Provides credible evidence to ratepayers
4. Complies with FERC and Oregon Commission Guidelines

4

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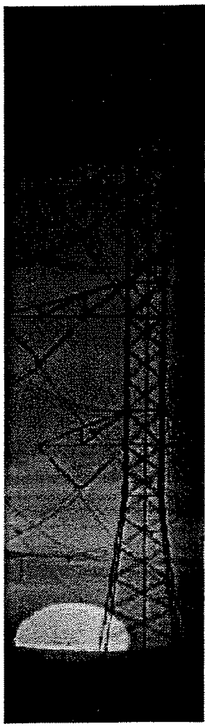

I. TO ASSURE THE BEST DEAL FOR RATEPAYERS, THE METHODS FOR BID AND BENCHMARK EVALUATION MUST BE FAIR AND TRANSPARENT

B. How to Achieve Fairness and Transparency?

1. Precisely define product(s)

2. All parties bid under same non-price terms

3. Price only (or price mostly) evaluation

5

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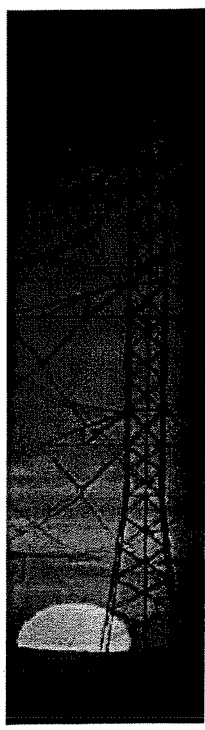

II. ALIGNMENT OF THE RFP WITH AN ACKNOWLEDGED IRP

A. The Oregon Commission has ruled that the RFP is not aligned with an acknowledged IRP

1. Neither level or nature of need is agreed upon

Year	PacifiCorp*	Oregon Commission**	Utah Commission***
2012	808 MW	157 MW	N.A.
2013	1,109 MW	335 MW	1,700 MW
Nature	Baseload	Peaking	Baseload

* PacifiCorp – November 1, 2006 Draft RFP p. 6.

** UM1208 – Order No. 07-018 "Disposition: Request for Approval of Draft RFP Denied" 1/16/07. p. 5, referring to Staff's Reply Comments on PacifiCorp's revised RFP. 11/19/06. p. 4.

***Utah PSC Docket No. 05-035-47. "PacifiCorp 2012 RFP Suggested Modifications." 12/21/06. This excludes 700 MW of planned Front Office Transactions; uses 15% planning margin.

6

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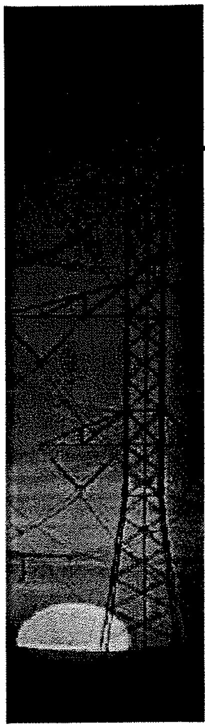


II. ALIGNMENT OF THE RFP WITH AN ACKNOWLEDGED IRP

A. Oregon Commission has ruled that the RFP is not aligned with an acknowledged IRP (cont).

1. The Oregon Commission has ruled that basic strategic issues remain unresolved.
    a. Baseload versus seasonal peak need (e.g., reliance on surplus sales)
    b. Risks and benefits of delay (i.e., "bridging" strategy to permit IGCC maturation)
    c. Opportunities for all sources (e.g., more renewables, DSM, distributed generation, short-term purchases)

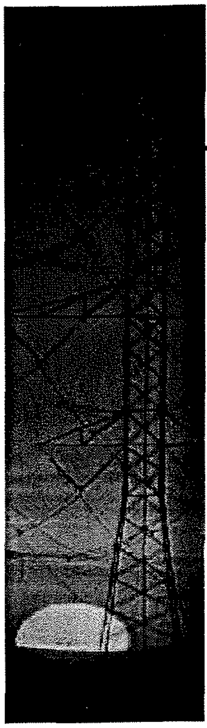
II. ALIGNMENT OF THE RFP WITH AN ACKNOWLEDGED IRP

B. Observations

1. Neither a well-defined product or a price-mostly evaluation

2. RFP becomes a "shadow IRP"
    a. Limits on how a RFP can inform an IRP
    b. Must provide bidders with full IRP analysis supporting benchmarks

3. Evaluation must be designed to address Oregon Commission strategic issues
    a. Assess or consider more sources
    b. Define analytic approach
    c. Re-assign risk



III. RATEPAYER RISK ACROSS TRANSACTION TYPES

A. Risk is pervasive
   1. Evaluation must incorporate risk to find the best deal
   2. Risk must be assigned explicitly through transaction documents

B. Ratepayer risks (and benefits) vary by transaction type
   1. From traditional cost plus regulation to pay-for-performance PPA (see table; ✓ indicates risk shifted to supplier)

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III. RATEPAYER RISK ACROSS TRANSACTION TYPES

Empty box indicates ratepayer bears risk, ✓ indicates risk typically shifted to supplier before the fact

Types of Risks	Cost-Plus Ratemaking	EPC Agreement	Asset Purchase (Plus O&M)	Tolling Agreement	Pay-for Performance PPA	Full Requirements Default Service
1. Development Risk						
a. Installed Cost						
i. EPC		✓	✓	✓	✓	✓
ii. Soft Costs			✓	✓	✓	✓
iii. Finance			✓	✓	✓	✓
b. Reliability at Start		✓	✓	✓	✓	✓
c. Environmental Start		✓	✓	✓	✓	✓
2. Operating Risk						
a. Operating Cost						
i. Fuel Price					✓	✓
ii. Heat Rate				✓	✓	✓
iii. O&M				✓	✓	✓
b. Reliability				✓	✓	✓
c. Environmental				✓	✓	✓
3. Regulatory Risk						
a. Disallowance						
b. Environmental						
i. CO_2						✓
ii. Other				✓	✓	✓
4. Market Risk						
a. Need for Power						✓
b. Price of Power						✓

10

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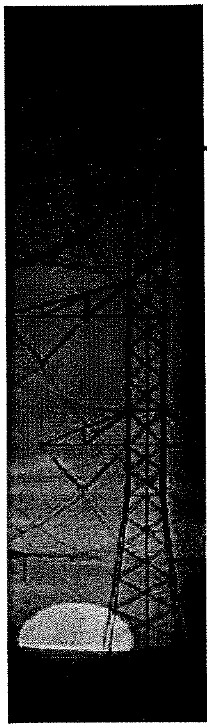

III. RATEPAYER RISK ACROSS TRANSACTION TYPES

C. Observations
  1. Two alternatives
     a. Quantify risk and benefits by transaction type, or
     b. Hold all bids and benchmarks to same risk assignment standard
  2. Diversity by transaction type not necessarily mitigation of ratepayer risk

11

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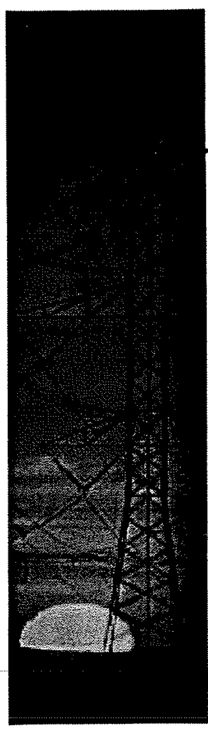

IV. RATEPAYER RISK ACROSS TECHNOLOGY TYPES

A. Risks vary by technology type
  1. Capital cost risks for coal
  2. Fuel price risks for natural gas
  3. Performance risk for some renewables

B. Non-price factors are a limited risk analysis for Initial Shortlist

C. PacifiCorp's Stochastic and Scenario risk assessments have merit

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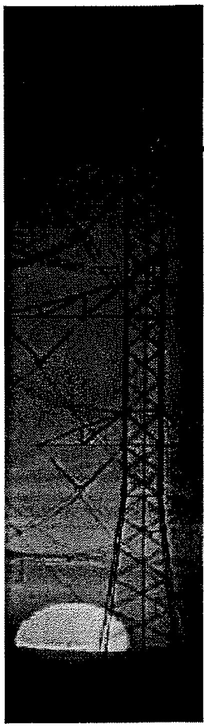

IV. RATEPAYER RISK ACROSS TECHNOLOGY TYPES

D. Observations

1. Innovative Technologies (e.g., IGCC) are given adequate opportunity to bid

2. More detail for non-price factors required

3. Expand list of risks considered
   a. Capital cost risk
   b. Power sales risk
   c. Volatility for all fuels
   d. Performance risk

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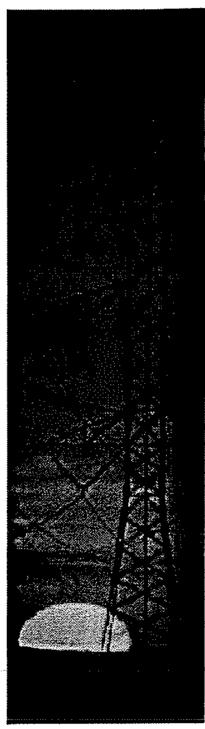

V. THE RISK OF FUTURE CO_2 REGULATION

A. Increasingly plentiful and credible evidence

B. RFP must address level and nature of risk

C. PacifiCorp approach has merit
   1. $8 per ton base case in line with less strict policies

   2. $25 to $40 per ton sensitivities in line with more aggressive policies

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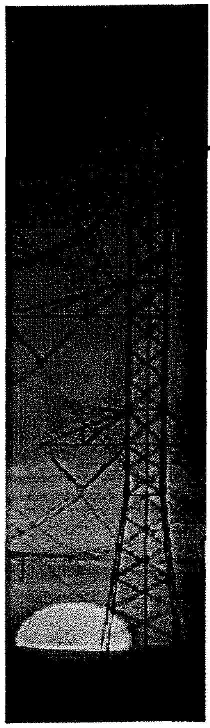


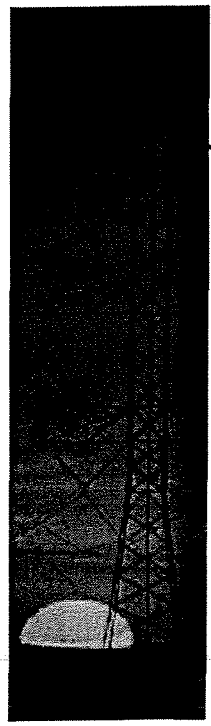
V. THE RISK OF FUTURE CO_2 REGULATION

D. Observations

1. Close open-ended ratepayer risk with specific standards

2. Scenarios with $25 to $40 must be included in PVRR, also find "tipping points"

3. Assess effect of policy other than tax or cap and trade (i.e., emissions standards)

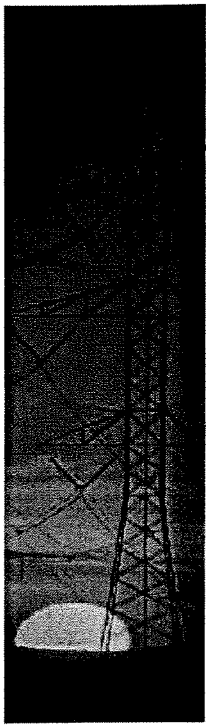


VI. IMPUTED DEBT

A. PacifiCorp approach has merit

1. Not included in Initial or Final Shortlist

2. Actual consequences for cost of capital reflected



VII. NETWORK RESOURCE STATUS

A. Comparability issues
   1. Same models and method

   2. Comparable results

   3. Who pays? (i.e., Duke-Hines precedent)

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VIII. DETAILED ANALYTICAL TECHNIQUES EMBEDDED IN MODELS

A. Unequal lives
   1. Nominal annuity method is best

   2. "Filling in" with market purchases can be a bias toward Benchmarks

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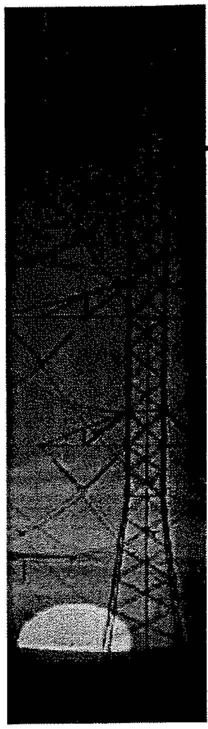

IX. STAKEHOLDER FEEDBACK

A. Questions

B. Additional concerns

C. Next steps

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Attachment C
STAKEHOLDERS' MEETING

PacifiCorp 2012 RFP
Accion Group, Inc. - January 31, 2007

I. Areas of Review by Accion
- *Draft PPAs*
- *Draft Tolling Agreements*
- *Bidder Qualifications & Credit Requirements*
- *Benchmark Requirements*
- *Facility Requirements*
- *Fuel Supply Requirements*
- *Process & Draft RFP*
- *Code of Conduct*

II. Materials Under Review
- *Owner's Development Assumptions*
- *Owner's Costs under APSA*
- *S& P Inferred Debt Method*

III. Materials Given Limited Review
Accion Group reviewed the following documents only to confirm they were provided by PacifiCorp to prospective bidders

The sufficiency and legal significance of the documents must be determined by bidders.

- *Site Purchase Agreement*
- *Real Property Purchase and Sale Agreement*

IV. IE Preliminary Review
- *RFP documents are clear and comprehensive.*
- *The products sought are adequately defined.*
- *Proposed RFP protocols are reasonable.*
- *If implemented as designed, PacifiCorp's protocols could*

- *provide for a fair and transparent RFP.*
- *Credit requirements are within the range of other RFPs.*
- *The benchmark descriptions are sufficient for marketers*
- *to understand parameters.*

V. Areas Undergoing Further Review

Bidder qualifications requirements.

Code of Conduct:

- *Affiliate Separation*
- *Training Materials*
- *Protocols*

Communication Protocols

Limits on post-bid negotiation of terms to meet technical and operational requirements:

- *PPAs*
- *Tolling Agreements*

ATTACHMENT FIVE
PACIFICORP'S BASE LOAD RFP, CEM ANALYSIS
(DECEMBER 10, 2007) (EXCERPT ONLY)

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Base Load RFP

IRP Analysis

Highly Confidential

December 10, 2007

2012 Base Load RFP

IRP's System Optimizer Model

Scenario Case Names

12% Planning Reserve Margin

Natural Gas Prices	Carbon Dioxide Prices: Low	Medium	High
Low	**Case 1**	**Case 2**	**Case 3**
Medium	**Case 4**	**Case 5**	**Case 6**
High	**Case 7**	**Case 8**	**Case 9**

15% Planning Reserve Margin

Natural Gas Prices	Carbon Dioxide Prices: Low	Medium	High
Low	**Case 10**	**Case 11**	**Case 12**
Medium	**Case 13**	**Case 14**	**Case 15**
High	**Case 16**	**Case 17**	**Case 18**

12% Planning Reserve Margin

Coal Prices	Carbon Dioxide Prices: Low	Medium	High
Low		**Case 19**	
Medium		***Case 5***	
High		**Case 20**	

2012 Base Load RFP

IRP's System Optimizer Model

Resource Selection by Case

12% Planning Reserve Margin

Natural Gas Prices	Carbon Dioxide Prices: Low	Carbon Dioxide Prices: Medium	Carbon Dioxide Prices: High
Low	[redacted]		
Medium			
High			

15% Planning Reserve Margin

Natural Gas Prices	Carbon Dioxide Prices: Low	Carbon Dioxide Prices: Medium	Carbon Dioxide Prices: High
Low	[redacted]		
Medium			
High			

2012 Base Load RFP

IRP's System Optimizer Model

Resource Selection by Case

12% Planning Reserve Margin, Coal Price Cases

		Carbon Dioxide Prices		
		Low	Medium	High
Coal Prices	Low	[redacted]		
	Medium			
	High			

2012 Base Load RFP

IRP's System Optimizer Model

Resource Selection

Scenarios: 15% Planning Reserve Margin 1/ 3/

	Case 10	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18	Count	Rank
	$0 CO2	$8 CO2	$25 CO2	$0 CO2	$8 CO2	$25 CO2	$0 CO2	$8 CO2	$25 CO2		
	Low Gas	Low Gas	Low Gas	Medium Gas	Medium Gas	Medium Gas	High Gas	High Gas	High Gas		
[redacted]											

12% Planning Reserve Margin

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case19	Case20	Count	Rank
	$0 CO2	$8 CO2	$25 CO2	$0 CO2	$8 CO2	$25 CO2	$0 CO2	$8 CO2	$25 CO2	$8 CO2	$8 CO2		
	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Low Coal	High Coal		
	Low Gas	Low Gas	Low Gas	Medium Gas	Medium Gas	Medium Gas	High Gas	High Gas	High Gas	Medium Gas	Medium Gas		
[redacted]													

Difference — **15% PRM less 12% PRM**

										Count	Rank
	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal	Medium Coal		
	Low Gas	Low Gas	Low Gas	Medium Gas	Medium Gas	Medium Gas	High Gas	High Gas	High Gas		
[redacted]											

	15% PRM			12% PRM							
	Case 11	Case 14	Case 17	Case 2	Case 3	Case 5	Case 6	Case 8	Case 9	Case20	Build

[redacted]

ATTACHMENT SIX
COMPARISON OF ALL BIDS AND BENCHMARKS VERSUS THE PACIFICORP FORWARD PRICE CURVE

Attachment Six

Initial Price Screen Results

Bid	MW	Resource Category	Resource Type	Nominal Levalized Delivered Cost ($/MWh)	Break Even Nominal Levalized Delivered Cost ($/MWh)	Ratio of Cost to Market
[redacted]						

CERTIFICATE OF SERVICE

I certify that on May 30, 2008, I served the foregoing upon all parties of record in this proceeding by delivering a copy by electronic mail only.

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