BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp for Approval of a 2009 Request for Proposals for Flexible Resource	DOCKET NO. 05-035-47 **REPORT OF THE INDEPENDENT EVALUATOR ON PACIFICORP'S DRAFT 2009 RFP**

Report of the Independent Evaluator Regarding PacifiCorp's 2009 Request for Proposals For Flexible Resources

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Prepared by
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Report of the Independent Evaluator
Regarding PacifiCorp's 2009 RFP

Executive Summary

Merrimack Energy Group, Inc. (Merrimack Energy) was retained by the Utah Public Service Commission (Commission) to serve as Independent Evaluator (IE) for PacifiCorp's 2009 Request for Proposals (RFP) for Flexible Resources. One of the tasks required of the IE is to provide a written evaluation including recommendations to the Commission on approval of the proposed solicitation or modifications required for approval and the bases for the recommendations. This report is intended to meet that requirement.

The overall objective of the IE in this process is to ensure the solicitation process could reasonably be expected to be undertaken in a far, consistent and unbiased manner. As a component of the first phase of the process (i.e. review of the RFP and related documents) the objective of the IE is to ensure the RFP will lead to a fair and equitable process and whether or not the components of the RFP are consistent with industry standards. To accomplish these objectives the IE undertook the following activities:

- Reviewed the RFP documents and computer models in detail;
- Met several times with PacifiCorp in the presence of Utah Division of Public Utilities staff to discuss various elements of the RFP;
- Reviewed the suggestions by Navigant Consulting based on the 2003-A RFP for improvements in the process;
- Reviewed all questions of interested parties and the responses prepared by PacifiCorp;
- Reviewed the comments filed by all interested parties; and
- Compiled and reviewed several recent power supply RFPs as a means of comparing the components in Pacificorp's RFP to industry standards.

The IE has prepared its comments in three areas: (1) comments on specific aspects of the RFP document, including suggested formatting changes and revisions/modifications designed to make the document clearer to bidders; (2) comments on the attached contracts, with emphasis on the Power Purchase Agreement (PPA) and the Asset Purchase and Sale Agreement (APSA) as a means of assessing the risk sharing provisions of a power purchase option versus utility ownership; and (3) comments and recommendations on major issues identified by multiple parties and recognized by the IE as important to the fairness and equity of the process, including the economic evaluation methodology and associated models, credit issues, and accounting implications and debt impacts.

The IE is of the opinion that the RFP and related documents issued by PacifiCorp represent a good starting point for developing an effective competitive bidding process for new power supplies. Furthermore, the RFP does incorporate many of the suggestions made by Navigant Consulting, Merrimack Energy and others with regard to the 2003-A RFP. While the RFP is more transparent and provides a significant base of information for bidders to use to assess their competitive position, the IE has identified several revisions and modifications that should be considered before the RFP is issued. These issues are included in the list of conclusions and recommendations below.

Based on our review of the RFP and related information, the conclusions and recommendations of the IE are presented as follows:

1. PacifiCorp has developed a reasonably transparent process that provides the necessary information to bidders on which to base their proposal. In particular, the RFP documents clearly describe the products requested, the requirements of bidders, the evaluation and selection process, and the risk profile of the buyer. In this regard, there is sufficient information to allow bidders to assess whether or not to compete, the product of choice to bid to be most competitive, and the process by which their proposals will be evaluated.

2. The RFP represents a significant improvement over the 2003-A RFP. PacifiCorp has incorporated a number of the recommendations of Navigant Consulting, Merrimack Energy, and others. Specific steps such a including contracts for each project structure, identifying all the factors considered in the bid evaluation process and identifying how such factors will be incorporated, providing pricing forms for bidders to complete, and more clearly describing the bid evaluation and selection process leads to a more transparent process.

3. The IE has identified a number of specific issues and suggested modifications to the RFP document to ensure additional clarity and fairness to the bidders. Many of the modifications involve formatting suggestions and/or additional clarifications. For the most part, we would expect that such modifications would not materially effect the continuation and completion of the RFP process.

4. The IE believes several of the non-price criteria should be broadened to allow greater resolution to distinguish bids on a non-price basis. This includes the allocation of points or weights for both dispatchability and exceptions to the proforma agreements. The IE is of the view that the non-price criterion assigning a ten point binary weight for any exceptions to the pro forma agreements needs to be modified or eliminated. In addition, PacifiCorp may want to consider using the credit matrix concept as the basis for establishing a non-price criterion for credit considerations.

5. The quantitative methodologies developed by PacifiCorp for undertaking the initial price factor evaluation (RFP Base Model) and the final short list (production cost model) are applicable for the modeling of the proposals expected in this RFP. Furthermore, the model methodology is consistent with industry standards applied by others for conducting such a pricing analysis. While the RFP Base Model may be unique to PacifiCorp, the model methodology and concept is consistent with the approaches applied by others. Based on our initial review of the RFP Base Model, the IE has found no inconsistencies or biases in the model construct.

6. The IE will undertake a further test of the models using hypothetical bids. In this process, the IE will utilize the bid forms as contained in the RFP and create several test bids. The bids will be evaluated by PacifiCorp similar to the evaluation of actual bids. The IE will then review the results with PacifiCorp to determine if the model methodologies are

consistent, fair and unbiased. It is recommended that this process be implemented soon after PacifiCorp submits its comments in this proceeding in response to the IE's report.

7. The IE has found that the methodologies and approach used by PacifiCorp for forecasting fuel and power forward prices are reasonable and consistent with industry standards. PacifiCorp uses actual market quotes and transactions as the basis for short-term prices for both power and fuel and blends into a long-term fundamental forecast for the mid to long-term. The use of actual quotes and transactions is a valid approach for capturing market prices in the short-term which is preferable to using the fundamental forecast for all years of the forecast period. Furthermore, the use of actual quotes serves to minimize or eliminate any forecasting bias in the short-term based on the timing of forecast release or the failure of the forecast to account for market volatility.

8. The IE recommends that PacifiCorp develop the forecasts for key variables associated with the evaluation of the asset ownership and EPC options that the company will own and operate and provide and "lock-down" the forecasts to the IE at least two weeks in advance of receipt of bid. This would include forecasts of fixed and variable O&M costs, start-up costs, and fuel transportation costs.

9. The IE has raised several concerns with regard to the level of credit assurance required of bidders, particularly those with investment grade ratings. Also, the IE has raised several concerns over the level of credit assurance required of bidders for PPAs and asset purchase options. As noted in the discussion on contract issues in the report, the methodology used by PacifiCorp to calculate the level of credit assurance is not consistent with industry standards and is not consistent with traditional power contract damage provisions. The IE has identified several potential biases due to the level of credit assurance requirements including bias against smaller projects and a bias favoring asset purchase options relative to PPAs. The IE recommends PacifiCorp reconsider the level of credit assurance required and attempt to resolve the potential biases contained in the methodology.

10. Despite the biases contained in the level of credit assurance requirements, the IE concludes that the type of primary security required by PacifiCorp (i.e. letter of credit, guarantee or cash) and the Company's unwillingness to be subject to accounting or tax treatment that results from VIE treatment are consistent with industry standards.

11. The IE has conducted a thorough review of the two basic contract forms - - the PPA and the Asset Purchase and Sale Agreement (APSA). The IE views the subject PPA and APSA to be within the bounds of industry norms in each case. However, the place of each form relative to the bounds of industry norms is markedly different. The PPA form appears decidedly on the side which is tougher on Sellers than Buyers and significantly departs from a form which occupies a mid point among forms. The PPA can be characterized as a "Buyers Form", while the APSA does occupy a mid point among comparable forms. The IE believes that only the potential counterparties to these contracts can propose balancing revisions with the self-interest needed to offset PacifiCorp's interests. Even if PacifiCorp decides to make revisions to the present forms, the IE recommends that the binary weighting for exceptions to the contract as a non-price characteristic be removed from the scoring in all events and that either (i) exceptions go unscored and unpenalized or (ii) points be assigned to major issues in the forms and distributed in such a way that no bidder would experience more than a one point deduction in scoring for any single issue.

12. While the present RFP is much more transparent than the previous RFP with regard to accounting and debt impacts associated with purchased power, including the identification of the methodology proposed by PacifiCorp for assessing the impacts and the opportunity for bidders to assess their accounting treatment before deciding to submit a bid, there is still a wide disparity in the positions of the parties with regard to treatment of inferred debt. Furthermore, several parties to the proceeding have raised concerns about the appropriate treatment and associated risk for PPAs in comparison to the treatment and risk for rate base plants from the perspective of both the Credit Rating Agencies and the ratepayers. Unfortunately, no party to the case has proposed an alternative methodology, supported by studies or other evidence for putting PPAs and rate base plants on an equal footing. In addition, there is no industry standard associated with either treatment of inferred debt to reflect the risk associated with a PPA or treatment of the utility's cost of capital to reflect the risk associated with a rate base unit. The IE believes this is a major policy issue at the regulatory level that may require review and assessment by the Commission regarding the appropriate approach for assessing PPAs and rate base options. Should the Commission decide to assess this issue further in an existing proceeding or in this proceeding, we believe consideration should be given to conducting a parallel process to ensure the RFP stays on a reasonable track to ensure the resource needs for 2009 can be met.

I. Introduction

Merrimack Energy Group, Inc. (Merrimack Energy) was retained by the Utah Public Service Commission to serve as Independent Evaluator for PacifiCorp's 2009 Request for Proposals (RFP) for Flexible Resources. The scope of work for the assignment requires the Independent Evaluator (IE) to participate in all three phases of the solicitation process: (1) solicitation process approval; (2) solicitation process bid monitoring and evaluation and (3) energy resource decision approval process and to undertake the following tasks:

1. Review PacifiCorp's proposed solicitation process to assure it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to PacifiCorp's retail customers taking into consideration long-term and short-term impacts, risk, reliability and the financial impacts on PacifiCorp.

2. Review PacifiCorp's proposed solicitation process to assure the evaluation criteria, methods and computer models are sufficient to evaluate the benchmark option and prospective bids in a manner that is fair, unbiased and comparable, to the extent practicable, and that the evaluation tools will be sufficient to determine the best alternative for PacifiCorp's retail customers.

3. Review the adequacy, accuracy and completeness of all proposed solicitation materials to ensure the objectives identified above can be met. This includes ensuring the disclosure of evaluation criteria, methods and models.

4. Review and validate the adequacy and reasonableness of the proposed evaluation methods and any computer models used to screen and rank bids from initial screening to final resource selection. This task requires an assessment of the extent to which the evaluation methods and models are consistent with accepted industry standards and/or practices and the appropriateness of any adjustments made for debt imputation are assessed.

The Independent Evaluator is required to provide a written evaluation including recommendations to the Commission regarding the results of the above tasks including recommendations on approval of the proposed solicitation or modifications required for approval and the bases for the recommendations.

In addition to the Introduction, the report is presented in eight other sections. Section II provides a brief background on PacifiCorp's RFP process to date. Section III describes the process undertaken by the IE to date to assess and evaluate the RFP process. Section IV provides a summary of the positions on the parties to the case as presented in the comments filed by each party. Section V lists the suggested revisions to the 2003-A RFP identified by both Navigant Consulting and Merrimack Energy. Section VI lists the specific revisions and modifications to the RFP documents identified by the IE. Section VII provides detailed discussions of the key issues in the competitive bidding process including the modeling methodologies and models, credit issues, and accounting implications and debt impacts. Section VIII provides a detailed assessment of contract issues, particularly the differences in contract considerations between a Power Purchase Agreement (PPA) and Asset

Purchase and Sale Agreement (APSA). Finally, Section IX provides our conclusions and recommendations.

II. Background

PacifiCorp filed a draft of its 2009 RFP for Flexible Resources on June 27, 2005. The draft RFP is requesting 525 MW of flexible resources, with flexibility defined as capacity and energy that can be prescheduled the day before delivery or within the day of delivery. The Company is seeking proposals from all eligible suppliers who can deliver the power in or to PacifiCorp's Eastern Control Area by summer of CY2009. Bidders can propose terms up to 35 years or the life of the asset. Bidders could submit proposals for any one of eight products listed in the RFP plus two eligible resource exceptions (combined heat and power and load curtailment). The resource alternatives include power purchase and tolling services agreements as well as asset ownership and EPC options. The draft RFP was posted on PacifiCorp's website. The draft RFP provided a detailed description of the resource alternatives sought by PacifiCorp, the logistics for submitting a bid including the Appendices and Forms required with each type of resource alternative proposed, a description of the bid evaluation process and a description of the evaluation criteria to be used to evaluate and select bids. In addition, the RFP contained eleven Appendices and nineteen Attachments, including applicable contractual agreements.

PacifiCorp held a workshop for prospective bidders on June 14, 2005 and a Technical Conference in Salt Lake City on August 10, 2005. Interested parties were allowed to submit questions by July 26, 2005 with PacifiCorp committing to post responses by August 2, 2005. Four parties submitted questions to PacifiCorp, including the Independent Evaluator. Comments of the interested parties were filed on or around August 22, 2005. This report takes into consideration the responses by PacifiCorp to the questions submitted by interested parties as well as the comments filed by interested parties.

III. Approach of the Independent Evaluator

The overall objective of the Independent Evaluator is to ensure the solicitation process could reasonably be expected to be undertaken in a fair and consistent manner. The objective of this assessment was to:

- Identify any potential undue biases in the evaluation criteria, evaluation and selection process, and contractual arrangements.

- Assess whether the RFP and related documents will lead to a fair and equitable competitive bidding process.

- Assess whether the components of the process conform to accepted industry standards.

- Assess the likelihood the process will conform to the characteristics of an effective competitive bidding process.

- Determine whether or not the proposed RFP documents and associated attachments provide adequate and consistent information on which bidders can adequately prepare their proposals.

To accomplish these objectives the Independent Evaluator conducted several meetings with PacifiCorp (all in the presence of a Department of Public Utilities Staff member), reviewed the RFP documentation in detail, and reviewed and evaluated the attached contracts and other arrangements. In addition, PacifiCorp both described the models, methodologies, and input assumptions and forecasts underlying the pricing assessment and provided the Independent Evaluator with a copy of the RFP Base Model. In addition, PacifiCorp provided several model runs requested by the IE. This allowed the Independent Evaluator to thoroughly assess the adequacy of the RFP Base Model for proposal evaluation purposes.

In addition, the IE raised a number of questions seeking clarification of sections of or statements included in the RFP and contracts to ensure we understood the intent of these sections. The objective was to ensure there was no ambiguity in the directions of the RFP that could mislead or confuse bidders. The IE also met for a number of hours with PacifiCorp RFP team and legal staff to review and assess contract provisions for the various types of contractual arrangements proposed to ensure there were no undue biases associated with different contractual arrangements.

Also, the IE met with PacifiCorp to discuss the following issues: (1) the Company's approach for assessing transmission costs and arrangements; (2) the rationale and basis behind the credit matrix and the implications on different types of bidders; (3) the concepts and methodology underlying the debt imputation proposal; and (4) development of the forward curves for both power and natural gas.

In addition to reviewing the documents filed by PacifiCorp and conducting follow-up meetings to discuss key issues, the IE will also review and comment on sections of the RFP and related documents relative to industry standards. Such standards are based on Merrimack Energy's experience in other competitive bidding processes. In addition, Merrimack Energy has compiled a sample of recent power supply RFPs to use in establishing the industry standards. These include the following:

- Progress Energy Florida Request for Proposals for Power Supply Resources, October 2003.

- Portland General Electric Company Request for Proposals for Power Supply Resources, June 2003.

- Hydro-Quebec Distribution Call for Tenders Document (A/O 2004-02) Electricity Generated by Cogeneration, October 2004 (Note: Hydro-Quebec has issued several Call for Tenders over the past three years with the Cogeneration Call for Tenders being the most recent).

- Public Service Company of New Mexico Request for Proposals for Capacity Supply, August, 2004.

- Xcel Energy Request for Proposals for Dispatchable Resources, February, 2005.

- Georgia Power Company and Savannah Electric and Power Company 2009 Request for Proposals, July 2005.

IV. Positions of the Parties

As noted, interested parties were allowed to submit questions regarding the RFP by July 26, 2005. Questions on the draft RFP were submitted by Utah Association of Energy Users, the Division of Public Utilities, the Committee of Consumer Services, and by the Independent Evaluator. Comments on the draft RFP were filed on or around the due date of August 22, 2005 by the Division of Public Utilities, Western Resource Advocates, Northwest Independent Power Producers Coalition (NIPPC), Utah Association of Energy Users, and the Committee of Consumer Services. A summary of the comments and positions of each party is provided below.

Division of Public Utilities

The Division of Public Utilities focused its comments on two aspects of the RFP. First, the Division reviewed the recommendations of Navigant Consulting Group and Merrimack Energy with regard to PacifiCorp's 2003-A RFP relative to PacifiCorp's 2009 Request for Proposals for Flexible Resources (2009 RFP) and concluded that the current RFP is superior to PacifiCorp's 2003-A RFP in that it more fully fulfills the objectives of achieving an open, fair, and reasonable process.

The Division also addressed the screening evaluation proposed by PacifiCorp to arrive at a short-list of bids, in particular the inferred and/or the inclusion of direct debt costs in this stage of the evaluation. The Division also raised issues with respect to the risk posed by a self-build option. The Division identified two concerns about the process:

- The Division recommends the use of a 15% risk factor in determining the amount of debt to impute to a bidder's proposal during the screening evaluation. The Division indicates there is uncertainty with regard to the impact of certain contacts on the utility's cost of capital.

- The Division is also concerned about the effect of a self-build option on the utility's cost of capital and recognizes the importance of developing an approach for putting power contracts and self-build options on an equal footing.

The Division has sponsored testimony on these topics in Docket No. 03-035-14 and directs the Commission's attention to the Division's arguments contained in the direct testimony of Division witness Dr. William (Artie) Powell.

Western Resource Advocates (WRA)

Western Resource Advocates comments focus on two areas: (1) specific comments on the 2009 RFP and (2) general comments on resource planning issues.

With regard to the RFP, the comments of Western Resource Advocates are as follows:

- WRA supports the inclusion of small-scale distributed resources of 3 MW or more and load curtailment of 25 MW or more as resource alternatives in the 2009 RFP.

- WRA supports the Company's approach for the resources required as reasonable because the Company has indicated it will seek demand-side resources through other channels.

- WRA supports the inclusion of the CO2 proxy cost adder in the evaluation of bids. While WRA raises some concern about PacifiCorp's approach for including CO2 costs, WRA concludes that the important point is that the costs are reflected in the bid evaluation process.

- Until regulations implementing SB 26 can be developed, WRA suggests that PacifiCorp revise Section (4)(A) of its 2009 RFP to encourage bidders to submit innovative bids to address future air quality requirements and other environmental impacts including CO2 emissions and water use.

- WRA identifies the results of the IRP with regard to the addition of new wind generation resources and suggests more wind should be pursued by PacifiCorp.

Northwest Independent Power Producers (NIPPC)

NIPPC has significant concerns with regard to certain aspects of the RFP including the credit requirements, application of inferred debt or debt equivalency, exclusion of Variable Interest Entities from bidding, and the date required for keeping the bid open. NIPPC recommends that the Commission disapprove the RFP in its current form, resolve the inequities described in its comments and direct PacifiCorp to adopt the specific remedies outlined in its comments. A summary of the major issues raised by NIPPC is provided below:

- The credit requirements are unduly burdensome for creditworthy bidders. While PacifiCorp requires bidders to post letters of credit or corporate guarantees as credit support, NIPPC recommends that the Commission require PacifiCorp to amend the credit conditions in the RFP to reflect the ability of the PPA to incorporate subordinate liens, step-in rights, project finance indebtedness at the holding company level, or the ability of project lenders to assume PPA obligations.

- The application of an inferred debt or debt-equivalency risk factor of 50% unduly discriminates against long-term power purchase agreements (PPAs) and creates an irreparably damaging bias against PPAs. In order to ensure comparability in the evaluation of proposals submitted to satisfy the RFP requirements, including the utility self-build option, the Commission should undertake one of the following options:

  - Strike this section from the RFP
  - Reduce the risk factor to a maximum of 10%, which more accurately reflects Standard & Poors' current thinking in regard to the application of risk factors
  - Ensure comparable assessment of all risks and costs of both the competitive proposals under the RFP and any proposed PacifiCorp self-build alternative during the bid evaluation process.
  - Consider the provision of a return on the PPA "asset" for PacifiCorp, since it will be managing the performance of the contract, similar to what it does for the performance of its own power plants.
  - Consider the imposition of additional equity in the context of a PacifiCorp cost-of-capital proceeding, where all of the utility's risks and costs can be considered on a broader basis, rather than in this single bid evaluation.

- PacifiCorp's RFP states that the Company is unwilling to be subject to accounting treatment that results from Variable Interest Entity (VIE) treatment (see page 19). NIPPC states Variable Interest Entities should not be excluded from the RFP process since there is no consensus among the accounting and auditing industries as to which special purpose entities constitute VIE's and which would trigger VIE accounting treatment.

- NIPPC recommends that there should not be a requirement that the bidders should keep their bid prices open until March 2007. NIPPC recommends that the Commission should require PacifiCorp to allow the respondents some measure of flexibility to adjust their PPA contract terms to accommodate market changes during the period in question.

Utah Association of Energy Users

The Utah Association of Energy Users (UAE) provides a number of specific suggestions and recommendations. A summary of the suggestions and recommendations are provided below:

- UAE recommends that the Commission schedule a hearing, and solicit additional testimony and comments to address issues raised in the IRP Order.

- UAE recommends that the role of the IE should be summarized and emphasized at the beginning of the RFP, that the purported safeguards "contained within the design of the draft RFP" should be clarified and emphasized at the beginning of the RFP, and that other safeguards and assurances should be added.

- UAE is concerned that the requirement for each bid to identify one, but only one, resource alternative or PPA (page2) may discourage or penalize bidders who wish to package more than one resource into a single bid. Such bids should be permitted with only one fee.

- The Statement on page 3 of the RFP that QFs of more than 100 MW will not be eligible for capacity payments under the traditional PURPA contract should be removed from the RFP.

- Page 4 of the RFP (and elsewhere) references a “minimum” term of 20 years but does not mention a maximum allowable term. The RFP does not specify that the term of the bid can be for 35 years or the life of the asset.

- The RFP should clarify that PacifiCorp will commence negotiations for the use of a PacifiCorp site as soon as the short list is determined (page 4 and elsewhere).

- The proposed credit requirements for bidders (page 4 and elsewhere) are not reasonable. UAE fears that the proposed credit requirements will chill bidding and suggests that the Commission should determine acceptable credit requirements with the benefit of input from market participants and others. At a minimum, the RFP should clarify that various forms of security can be used in lieu of the minimum credit rating.

- UAE does not understand the requirement (page 5) that a TSA must propose to sell at least 85% of the project output to PacifiCorp. Absent a reasonable explanation for this requirement, it should be eliminated.

- Contractual surety and credit assurances should not apply to load curtailment bids from industrial customers.

- UAE recommends that the IE, in consultation with PacifiCorp, should make certain determinations relating to bids and bidding fees, rather than PacifiCorp.

- The debt imputation sections on page 19-20 should be stricken from the RFP.

- Requiring bidders to sign a declaration of the accounting impact on PacifiCorp (Page 19 & SFAS No. 13 Form, attached as Appendix F) is unreasonable and will likely chill bidding. If a certification is to be required, the import and consequences of the same should be specified.

- The RFP should clarify that, in addition to one face-to-face meeting with the IE and PacifiCorp, bidders are free to communicate with the IE at any time without the participation of PacifiCorp (page 22).

- Bidders should be allowed to refresh or revise their proposals on their own initiative if they discover errors or omissions, assuming it can be done in a manner and time so as not to hinder the evaluation (page 23).

- The first and second full paragraphs on page 27 are confusing and appear somewhat contradictory. The bolded language in the second full paragraph on page 27 should be clarified to apply only to bids involving a specified facility.

- UAE remains seriously concerned about the bid evaluation models (pages 32-38) for many of the same reasons raised by UAE in the Currant Creek docket. UAE believes that additional analysis, including a detailed and substantive review by the IE, is necessary before the proposed models can be approved as in the public interest.

- PacifiCorp's proposed scoring mechanisms (pages 32-36) fail to consider or assess impacts and risks to ratepayers of utility-owned resources.

- UAE does not believe that 60% is a sufficient weighting factor for price (page 32). The weighting is apparently based upon an Oregon requirement, but UAE believes that greater weight should be given to price factors (at least 70-75%).

- UAE questions the 20% and 10% weighting factors used for daily and day-ahead dispatch, respectively (page 35). The 10% weighting factor for day-ahead dispatch should be eliminated. A 10% weight should be given to daily dispatch.

- UAE disagrees with a binary weighting on pro forma agreement changes (page 35).

- The Commission should require PacifiCorp to clarify the model and criteria that it intends to use and require the IE, and permit other interested parties, to review, comment on and verify the same.

- UAE questions the determination of projected market prices based on two load shapes (i.e. 7x16 and 7x8) as the basis for evaluating bids. A careful and detailed analysis of this issue should be required by the IE before the use of these load shapes is approved.

- UAE requests the opportunity to submit further comments after it has received and reviewed PacifiCorp's responses to the IE's questions.

Committee of Consumer Services

The Committee raises two primary issues in its comments:

- The Committee's primary concern is that RFP 2009 does not allow for or address what IRP 2004 and the Committee concluded to be PacifiCorp's least cost, lowest risk resource acquisition strategy – the earliest addition of a large coal unit. The RFP again defers acquisition of this coal resource.

- As a condition to approval of RFP 2009, the Committee recommends the Commission require PacifiCorp, in its RFP evaluation, to consider the fact that in 2011 the IRP calls for the addition of a large coal unit. A determination of which bid submitted under the RFP is the best resource selection in 2009 should properly include consideration of a resource that is a bridge between the 2009 load and resource balance and the lowest cost/least risk resource identified in the IRP.

V. Revisions to the Competitive Bidding Process and RFP

PacifiCorp's RFP 2003-A was critiqued and several parties suggested improvements for inclusion in subsequent RFPs. A Utah special commission task force was convened to review the 2003 RFP. In addition, Navigant Consulting, the Outside Evaluator for the 2003 RFP process, provided a number of recommendations in its Final Report on PacifiCorp's RFP 2003-A (September 8, 2004). Finally, Merrimack Energy through the Direct Testimony of Wayne Oliver on Behalf of the Division of Public Utilities (In the Matter of the Application of PacifiCorp For a Certificate of Convenience and Necessity Authorizing Construction of the Lake Side Power Project, Docket No. 04-035-30), provided recommendations for improving the RFP process. The recommendations of Navigant Consulting and Merrimack Energy are provided below.

Recommendations of Navigant Consulting

- Encourage PacifiCorp to continue using Next Best Alternative's (NBA) consisting of both cost-based and forward-market based benchmarks.

- PacifiCorp should consider developing a component based PVRR spreadsheet for the NBA.

- A more detailed description of the Company's self-build option should be provided to bidders during the bid development period or as a separate section of the RFP.

- Develop two offer summary templates to include in future RFPs – one for PPAs and one for asset sale/turnkey offers. Consider using bracketed examples of the information being sought, as a guide for respondents.

- PacifiCorp should continue to use the same channels as used before to distribute the RFP in addition to publicizing its availability on the Company's website and various media resources.

- In future RFPs where future environmental risk and other risks present a material issue that PacifiCorp wants bidders to clearly state an assumption or rejection of in their proposals, include separate sections in the RFP dedicated to such topics.

- PacifiCorp should consider developing a proposal checklist for bidders to use as a guide in completing their offers.

- Whatever criteria are used in future RFPs, it should involve some scenario analysis to ensure that the scoring criteria are effective at allowing PacifiCorp to rank offers.

- In future formal solicitations like this RFP, PacifiCorp should include credit as one of the explicit criteria used for scoring and ranking offers.

- If credit is deemed inappropriate in the screening stage by PacifiCorp and its stakeholders, consider holding off on the formal request of credit and financial information, but provide bidders with a list of the information that they will need to have ready to submit to PacifiCorp within five days of being notified of making the Company's shortlist.

- In any pre-bid workshops held for future RFPs, dedicate a portion of the session(s) to explicitly directing bidders as to what PacifiCorp will be expecting from bidders in the responses with respect to their credit and financing arrangements in support of a transaction with the Company.

- In future RFPs, PacifiCorp should request all bidder information to be submitted on CD-Rom in a PDF format in order to facilitate the rapid dissemination of information to the personnel within PacifiCorp responsible for reviewing it.

- PacifiCorp should include a section in future RFPs that addresses issues such as the cost of direct and inferred debt.

- For future RFPs, there should be explicit language that states who will be responsible for securing the necessary transmission to support a proposed transaction, the bidder or PacifiCorp.

- Retain the existing analytical team, or comparable personnel, to complete future analyses for later RFPs.

- Consider using a component based PVRR that allows PacifiCorp to readily identify the magnitude and relative impact of modeling and assumption changes on a specific bid's valuation.

- When using an outside evaluator, consider using economic models that do not include extraneous information, formulas, and calculations that are not relevant for the screening or economic modeling of offers in the course of the RFP.

- Consider adding a few weeks into the schedule for future RFPs that involve modeling of multiple types of offers.

- PacifiCorp should eliminate the use of two separate economic models.

Merrimack Energy's Recommendations

Merrimack Energy also provided recommendations for improving the competitive bidding process in testimony filed in the Lake Side Power application (Docket No. 04-035-30). These recommendations include:

- In light of the selection process for separate products in the last RFP, Merrimack Energy recommended that PacifiCorp should undertake a portfolio evaluation process in its next

RFP. Under this approach, the price screening and non-price assessment is used to determine a short-list of bids and those bids are then combined into portfolios to assess the preferred combination of options.

- PacifiCorp should include a Model Power Contract(s) in the RFP. This allows bidders to assess the risk in the contract and reflect such risk in their bids. In addition, including a contract(s) can facilitate negotiations.

- PacifiCorp should include broader, more detailed non-price criteria in the next RFP.

- PacifiCorp should include the evaluation of credit-related issues in the early stages of the bid evaluation process.

- PacifiCorp should allot more time for contract negotiations if the company continues to use a competitive negotiations process.

- In its last RFP, PacifiCorp limited bid terms to 20 years but conducted a 35-year analysis. Also, PacifiCorp applied a debt adjustment in the evaluation of the final two bids. It is important in future RFPs that bidders are made aware of any important factors that could determine its bidding strategy and opportunity to compete. Such information should be transparent to bidders. Failure to identify such key factors influencing the evaluation of proposals submitted could dissuade companies from submitting a valid proposal.

VI. Assessment of the Competitive Bidding Process and Documents

This Section of the Report provides a discussion of our review of the RFP document, the methodologies used to evaluate bids, the evaluation criteria and key factors, and other related information. Before providing our assessment of the competitive bidding process and key documents, it is important to describe the factors Merrimack Energy feels are necessary for an effective competitive bidding process.

Characteristics of an Effective Competitive Bidding Process

In our view, an effective competitive bidding process should have the following characteristics:

1. The solicitation process should be fair and equitable, consistent, comprehensive and unbiased to all bidders. For assessing the documents and information at this stage of the process, the key criterion is bias, whether intended or unintended. Merrimack Energy's evaluation at this stage is designed to identify if any bias exists with regard to the type of products, resources, etc. that are allowed to compete in the process and the methods for evaluating and scoring the competing products. In Utah, fairness is now a statutory requirement. Senate Bill No. 26, enacted this year, requires that the solicitation process be approved in advance against a public interest standard and that an Independent Evaluator monitor the solicitation process to assure fairness.

2. Scoring and evaluation of proposals can be free of intended and unintended bias only if similarities in proposals are evaluated and scored similarly and differences in proposals are evaluated and scored differently. In identifying similarities and differences, all costs, benefits and risks of competing proposals must be accurately identified and fairly assessed.

3. The solicitation process should ensure that competitive benefits for utility customers result from the process. In this regard, it is important to determine whether all costs to consumers are reflected in the evaluation process so that true competitive benefits emerge in both the intra resources and inter resources comparisons.

4. The solicitation process should be designed to encourage broad participation from potential bidders. In this regard, it is important to assess whether the process is sufficiently transparent to allow bidders to determine how they can best compete in the process and sufficiently balanced so that no potential bidder faces uneven burdens or enjoys uneven advantages.

5. The Request for Proposal documents (i.e. RFP, Information required from bidders, and Model Contracts) should describe the bidding guidelines, the bidding requirements to guide bidders in preparing and submitting their proposals, the bid evaluation and selection criteria, and the risk factors important to the utility issuing the RFP. The RFP documents should effectively inform bidders how they can compete in the process.

6. The solicitation process should include thorough, consistent, and accurate information on which to evaluate bids, a consistent and equitable evaluation process, documentation of decisions, and guidelines for undertaking the solicitation process.

7. The solicitation process should ensure that the resource contracts are designed to provide a reasonable balance between the objectives of the counter-parties, seeking to minimize risk to utility customers and shareholders while ensuring that projects can reasonably be financed. Differences in the project contracts should be fairly reflected in the evaluation and selection process.

8. The solicitation process should incorporate the unique aspects of the utility system and the preferences and requirements of the utility and its customers.

Assessment of the Overall RFP and Competitive Bidding Process

Merrimack Energy has undertaken a high level assessment of the RFP relative to the 2003-A RFP and relative to industry standards. Our general conclusion is that this RFP is a significant improvement over the previous RFP. PacifiCorp has evaluated the comments and recommendations of Navigant Consulting and Merrimack Energy and has incorporated many of the comments in the design and development of this RFP. Some of the major improvements include:

1. PacifiCorp has developed contracts for each project structure or resource alternative sought and included the contracts in the RFP. This provides bidders the opportunity to assess the

risks in the contracts and include such risk in their proposals or decisions to compete. In addition, the contracts are linked to the RFP document and other attachments.

2. As will be discussed later, PacifiCorp has begun to expand its evaluation methodologies to be able to undertake a portfolio optimization process in the near future.

3. The 2009 RFP is much more transparent than the 2003-A RFP, which was silent on a number of key issues. For example, in the 2003-A RFP bidders had no idea at the time they submitted their proposals that debt impacts would be included in the evaluation process if the arrangement triggered lease accounting treatment. The 2009 RFP identifies that debt impacts are proposed to be included in the evaluation process and describes how the methodology to reflect the debt impacts will be addressed.

4. The Pricing Forms are detailed and should serve to ensure that consistent information is provided by all bidders.

5. The RFP does a more effective job of identifying the information required of bidders and the basis for the evaluation and selection process.

6. The process identified by PacifiCorp to characterize the bids by Resource Alternative and effectively evaluate bids within the same categories for purposes of determining the short-list allows “similar bids” to first compete against one another within each resource alternative class . This process should ensure that all resource types should be allowed to compete in the final short-list at the production cost stage of the evaluation.

While we believe this RFP is an improvement over the 2003-A RFP and is generally consistent with industry standards, the IE does have some suggested specific revisions or changes with regard to the RFP and related documents designed to make the RFP clearer to bidders. These issues largely focus on the format and structure of the RFP as well as suggestions for clarifying sections of the RFP. The IE also identifies several issues that may not be consistent with industry standards and could influence the fairness and equity of the evaluation and selection process in a subsequent section of this report.

Specific Comments of the IE Regarding the RFP

Merrimack Energy has reviewed the RFP document in detail and has a number of comments on the RFP document. Comments on other Appendices and Attachments will be provided in appropriate sections of this report. For example, Section VIII contains a detailed discussion about the underlying contracts in Attachments 1 to 19 to the RFP.

1. We would recommend including a section as an Appendix to the RFP that identifies the specific protocols and procedures that outline communications between PacifiCorp, the IE and Bidders.

2. On the top of page 2, it is stated that bids may be disqualified for failure to comply with any of the requirements outlined in this document. It is suggested that PacifiCorp identify and list these requirements in a specific section of the RFP so bidders know what these conditions are.

3. Page 4: PacifiCorp should describe in more detail in the RFP the basis for the quantity required of no less than 85% of the facility's dependable capacity in addition to the Company's response to Independent Evaluator Data Request 1.7..

4. Page 4: in the event the bidder proposes to locate a project on a PacifiCorp site, at what point does the bidder need to begin negotiations to enter into a lease or other acceptable agreement? PacifiCorp should clarify these requirements in the RFP.

5. Bottom of page 5: PacifiCorp should identify if excess capacity exists on the natural gas lateral to the PacifiCorp sites.

6. Since many of the conditions are similar for each of the Resource Alternatives, the IE suggests that PacifiCorp include a table in the RFP summarizing the requirements for each of the resource alternatives.

7. For each of the resource alternatives in which PacifiCorp will own the facility, the RFP should identify over how many years each alternative will be evaluated.

8. Page 13: The references in paragraph one are inconsistent. For example, paragraph 1 states that bidders must return the RFQ Bid Form (Appendix A and B). However, there is no reference to "Bid Form" in Appendix A or B.

9. Page 13, Submission of bids: Bids will be submitted to the Public Service Commission's office to the attention of the IE.

10. Credit Issues, page 16: The first full paragraph states that the bidder will be required to demonstrate its ability to post credit assurances in the amounts outlined in the Credit Matrix. How will bidders be required to demonstrate their ability to post credit?

11. Page 17, First Paragraph: The reference to Appendix A appears to be inaccurate for submission of the proposal on December 1, 2005. It appears that the information requested in Appendix A should be submitted in October based on the proposed schedule in the RFP.

12. Page 17, Section (c): This section states that bidders must include a statement that the terms and conditions of the Attachment for each resource alternative are acceptable. This appears to be inconsistent with the non-price criteria that allows bidders to take exceptions to the contracts.

13. Page 22, Communications: PacifiCorp should include the agreement between the Commission Staff, The IE and PacifiCorp that bidders will submit questions to the IE's

website only after the RFP is formally issued. From the time leading up to issuance of the final RFP, bidders should communicate via PacifiCorp's website.

14. Page 23, RFP 2009 Proposal Content: The IE feels that the requirements outlined in this section are unclear and somewhat confusing with regard to the information required of bidders. In addition, it is not clear if the information requested of bidders as described on this and the next few pages is supposed to be consistent with the information identified in Appendix C. If so, changes are required to conform the RFP document to Appendix C. The following are other specific issues which are unclear:
    a. Section 3) Complete set of applicable forms? Is PacifiCorp referring to Form 1 and Form 2 or all the Appendices and Attachments identified on pages 24-26?
    b. Section 4) Experience: Provide an explanation of the information PacifiCorp is looking for under this section.

15. Page 34: The IE and PacifiCorp have had discussions about the methodology contained on page 34 for assessing the Price Factor Weighting. The IE has suggested that if the range of forward prices specified does not conform to the actual range of prices submitted, it is possible that non-price criteria may have a much larger weight in the final selection, contrary to the 60% price and 40% non-price original split. PacifiCorp has agreed on a possible revision to the methodology that is consistent with the approach proposed by the IE.

16. Page 34-35: Non-Price Weighting Factors. It is the position of the IE that there needs to be greater resolution associated with the non-price category.
    a. With regard to dispatchability it is not clear if PacifiCorp would value a resource that offers real time dispatch and allows the unit to go to zero output more than a resource that limits output to half load. The current criterion does not distinguish the difference. The IE feels that this non-price criteria should be expanded to ensure there is a broader distinction between proposals
    b. The IE is concerned about the binary weighting associated with exceptions to the contract. This issue is addressed in more detail in the Contract assessment section of the report.
    c. While the IE recognizes that these criteria would be used to evaluate like resources in each resource alternative cluster, it is still important to provide a clear message to bidders about the characteristics of most value to PacifiCorp.

17. Appendix A: Section 2 Bidder Qualification: For question 4, PacifiCorp should be more specific about the minimum information bidders are required to provide to ensure there is a consistent base of information provided by all bidders.

18. Appendix B: Credit Matrix: The credit matrix contains several biases including:
    a. There is a bias against small projects. For example, a 3 MW project would require as much security as a 25 MW project. The IE feels that for CHP projects, the credit requirements should be required on a $/kW basis to eliminate this bias. Based on this approach, the credit requirements will vary based on proposal size and smaller project would not be unduly biased.

b. PacifiCorp has not formally explained why some eligible resources (i.e. C1, C2, and C8) have a much higher risk than other eligible resources (i.e. C3, C4, C5, C6, and C7). See further discussion below.
c. As will be discussed in more detail below, the magnitude of the credit requirements exceeds industry standards.

In addition to the above suggestions regarding the specifics of the RFP documents there are other issues either raised by interested parties in their comments or raised via questions and answers that should be considered to enhance the RFP process.

- One party raised several questions about the role of the IE. In other jurisdictions we have prepared a Scope of Work which has been included in the RFP filing. It is suggested that the IE and PacifiCorp, with input from the Commission, define such a Scope of Work and include it as an Attachment to the RFP.

- The issue of bid fees was raised by at least one participant. The IE has reviewed other recently issued RFPs. The results demonstrate that the fees requested by PacifiCorp are consistent with industry standards.

The IE is of the opinion that many of these issues could be resolved in a straightforward manner.

VII. Discussion of Important Competitive Bidding Issues

Based on the comments of the participants in the case as well as Merrimack Energy's own view of the key RFP issues, this section of the report will provide a more detailed assessment and discussion on the following issues: (1) the economic evaluation methodologies and models; (2) Credit issues; and (3) direct and inferred debt. Each is discussed in some detail below.

Economic Evaluation Methodologies and Models

PacifiCorp will rely on several economic models and methodologies for undertaking the price evaluation of the eligible bids. According to the draft RFP, PacifiCorp indicates that it will utilize a spreadsheet model ("RFP Base Model") to screen the proposals and to evaluate and determine a short list, and then use a production cost model to determine the final short list and the least-cost/risk resource(s). PacifiCorp provides a description of the RFP Base model inputs in the RFP.

The IE has met with the staff at PacifiCorp on two occasions to discuss the models to be used for the analysis, the methodologies underlying the economic evaluation of the bids, the development of major inputs to the models (i.e. forward curves for power and gas), and the major assumptions used in the evaluation. The IE's focus was to ensure the modeling approach and assumptions used don't create any undue biases favoring any resource alternative and that the methodologies are consistent with industry standards.

While this section of the report will discuss the applications of the models and key findings from our assessment, it is important to note that further testing of the models will take place prior to receipt of bids. The IE proposed as an optional task in its proposal to the Utah Public Service Commission to serve as Independent Evaluator to develop hypothetical bids to test the modeling methodology and the evaluation system based on the requirements of the RFP. The Public Service Commission approved the optional task and the IE will develop hypothetical bids and test the models and outputs from the model runs based on the bids. The combination of detailed review of the RFP Base Model, the production cost model used for determination of the final short-list, detailed discussions of the major assumptions and inputs and testing of the models using actual data will allow for a thorough evaluation of the pricing methodologies by the IE.

For purposes of the evaluation, the quantitative methodologies used will be very important at each stage of the process. As noted, PacifiCorp proposes to use two models for this process: (1) the RFP Base Model which will be applied at the initial screening phase of the evaluation; and (2) a Production Cost Model to be used to select the preferred options for contract negotiation. There has been consideration regarding the development of a portfolio optimization model for undertaking the detailed evaluation leading to the selection of the preferred resource. However, based on discussions with PacifiCorp, the model has not been adequately tested at this point and is not ready for this assessment.

A. RFP Base Model

The RFP model is a spreadsheet based model designed with the capability of conducting analysis of a number of products based on the optionality and value embedded in each product. The model contains several modules or blocks that are used depending on the type of product and the embedded optionality to be analyzed. The model has the capability for evaluating the eight major alternatives requested in the RFP. In addition, based on the recommendation of Navigant, PacifiCorp has expanded the model to include a ratebase tab to allow for the evaluation of ratebase options within the same model construct. As noted, in the previous RFP, the ratebase model was separate from the RFP model which caused additional work to ensure the inputs and assumptions were consistent between the models.

The model compares the cost components of each bid with the revenues the proposal would generate based on the projected market price of power times the projected level of output. In effect, the net present value of the revenue stream (assuming the energy could be sold at the projected market price) over the proposal term is compared to the net present value of the cost streams over the same term. The model includes the costs proposed by the bidder including capacity cost, fixed O&M cost, variable O&M cost, fuel cost, and start-up cost. In addition, the model adds transmission costs, CO2 adder, and debt impacts. In the screening phase, proxy transmission costs will be included. The draft RFP describes how transmission costs will be evaluated and provides estimated integration costs in Attachment 13. PacifiCorp also indicates in response to Request Set 1, Question 36 that it intends to augment its assessment of transmission costs via a new study to further assess such costs.

The calculated difference between costs and revenues is then divided by the real levelized contract capacity to estimate a Present Value Revenue Requirement (PVRR) in dollars per kW-month for each bid. Bids are then ranked with those bids having the highest positive value per kW-month ranking highest.

For purposes of undertaking the analysis, PacifiCorp proposes to develop two pricing patterns for specifying the forward market price for comparison purposes; (1) 7x16 hours and (2) 7x8 hours. PacifiCorp proposes to include the highest revenue generated from each of the two patterns in determining the revenues based on the differences between market prices and the variable cost of the proposal. PacifiCorp's rationale for this approach is that it does not need energy during the low-load hours, with transmission constraints actually limiting the delivery of power out of PacifiCorp's control area. In addition, if the load shape evaluated included more hours than 7x16, PacifiCorp would have to back down its existing coal units to accept additional energy beyond the 7x16 hours.

In addition to the direct costs and revenues contained in the model, PacifiCorp includes three additional costs: (1) transmission costs, including the costs to integrate the resource into the transmission system, as well as interconnection upgrade costs; (2) costs associated with direct or inferred debt based on the accounting treatment of the bid; and (3) CO2 costs based on the base case assumptions included in the 2004 IRP. In these cases, the RFP specifically identifies these cost elements and describes the methodologies used to incorporate the costs. While there may be some issues with regard to the level of costs included, the methodology used to estimate such costs or the appropriate application, the RFP document does include a detailed description of these cost elements, contrary to the 2003 RFP.

PacifiCorp has provided the IE with the model and Merrimack Energy has conducted an initial review of the model methodology and equations to ensure the model outputs are consistent and reasonable. The model methodology is consistent with industry standards applied by others for conducting such a pricing analysis of bids received. Furthermore, based on our initial review it appears the operations of the model track consistently from case to case. The inclusion of the Pricing Input Sheet (Form 1), which the bidder is required to complete and submit, should minimize any interpretation errors on the part of PacifiCorp's analysts and serves a s means of verifying the inputs submitted.

The Pricing Input Sheet also provides a "check" for the IE to ensure the input assumptions presented by the bidder are appropriately incorporated in the model. The Pricing Input Sheets are a valuable addition to the RFP. However, Merrimack Energy has a comment below on potential additions to the Pricing Input Sheet.

Also, as previously noted, we plan to test the model(s) in more detail using hypothetical bids. This will include completing the Pricing Input Sheets and other information required from bidders and submitting such information to PacifiCorp. PacifiCorp would then review and evaluate each bid as if the bid was an actual proposal. The IE will review the results with PacifiCorp and jointly determine if there are any needed revisions. The results of that test will either confirm the validity of the model or lead to suggested revisions, if warranted.

B. Production Cost Model

The IE met with PacifiCorp to discuss the production cost model and methodology proposed by PacifiCorp for determining the final short list and the least-cost/risk resource. PacifiCorp plans to use the Planning and Risk Module in the EnerPrise Suite. This model is driven by the PROSYM simulation engine for unit dispatching purposes. PROSYM is a long standing production cost model with many users in the electric utility industry. The model optimizes dispatch of the company's generation units against company load on an hourly basis for 20 years. The analysis will only consider the PacifiCorp system. The model has the ability to undertake a stochastic assessment and PacifiCorp has indicated its intention to prepare a stochastic assessment. The model has a Portfolio Optimization module but PacifiCorp indicated it did not intend to use such a module at this time until the module can be tested.

Included among the fundamental drivers of the model are fuel prices, hydro output, load, unit availability, status of new generation, and emission markets. The model does not produce a forward price but uses forward gas and electric prices as inputs.

The IE has worked on a number of competitive bidding projects with utilities where such models as PROSYM, PROMOD, EGEAS, or other production cost or generation expansion models were used to undertake the detailed or final short-list evaluation. As noted, PROSYM and other PROSYM-related models are well established in the utility industry. The methodology used is consistent with industry standards in undertaking similar competitive bidding processes. Since PacifiCorp is requesting bids for a certain specified resource type, the model should be sufficient for identifying the preferred resources.

Notwithstanding the model methodology, however, it is important to ensure the methodology is producing consistent results. The IE will therefore test the model based on the hypothetical bids previously identified. In addition, in past solicitations, the IE has requested output reports prepared by the utility to serve as a check on the consistency of model output. For example, for gas-fired combined cycle and combustion turbine projects, output reports contain information on the dispatch price (fuel commodity and variable O&M costs), the capacity factor of the unit, and any operating constraints that may explain any differences can be provided by PacifiCorp. The IE will request such reports to ensure the model is producing consistent results and will also review model output for the evaluation of bids.

While it is important to ensure consistent output, probably the major driver of the process is the inputs and assumptions used in the evaluation. The key fuel price assumptions and the methodologies for developing these forecasts are described below.

C. Power and Fuel Price Forecasts and Forward Curves

Several parties to the IRP as well as this proceeding have raised issues about the implications of recent natural gas prices on the choice of resources. Certainly, in many of the competitive bidding processes in which we have been involved, fuel price forecasts have come under scrutiny. In particular, the recent rapid increase in natural gas and oil prices is having an impact on the evaluation methodologies and bid evaluation approaches undertaken by utilities.

Based on our experiences, one observation has been that most traditional forecasts prepared by government (i.e. Energy Information Administration) or private companies tend to understate fuel prices (particularly natural gas), particularly in the short-run. In addition, these entities may only publish their forecasts annually or at most quarterly. Thus, in period of volatile prices it is difficult to reflect recent movements in prices in the early years of a long-term forecast.

In our view, PacifiCorp has developed a reasonable approach for forecasting long-term fuel and power forward prices. For both fuel and power prices, PacifiCorp uses actual market quotes and transactions as the basis for developing the forward curve for the first six years of the forecast. PacifiCorp then blends in the market forecast to the long-term projection for the next one to two years. For forward power prices PacifiCorp uses Midas Gold, a well known power price forecasting model for its long-term projections which takes into account transmission constraints, the cost and operating characteristics of new build options, fuel prices and a number of other inputs. For natural gas, PacifiCorp uses market quotes for six years and then blends in the next few years to the forecasts of a well recognized forecasting organization.

In our view, the approach used by PacifiCorp for developing forward prices for power and fuel is reasonable and is consistent with industry standards. Furthermore, the forecasts minimize any potential forecasting bias in the short-term because the forecasts are based on actual market quotes. In this case, if counterparties are hedging the risk of fuel cost volatility, the market quotes will incorporate these costs in the forecast.

D. Conclusions and Recommendations on the Models and Methodologies

Based on our initial reviews of the models (i.e. RFP Base Model and Production Cost Model), meetings with PacifiCorp staff to discuss the model methodologies and applications, and industry standards from other RFP processes, the IE concludes that the methodologies proposed by PacifiCorp are reasonable and should result in fair and equitable results. However, the input assumptions used in the bid evaluation process could have important impacts on the bidding results. We believe the approaches used by PacifiCorp for developing forward prices are reasonable and should minimize any undue bias associated with lower than expected fuel prices.

Nevertheless, the IE has a few recommendations to improve the modeling approaches and bid evaluation process:

- PacifiCorp should revise the Pricing Input Sheet (Form 1) in the RFP. This should including adding a section that allows bidders to specify a fuel price and/or fuel index which would serve as the basis for the fuel commodity price. There is a fixed energy payment block on Form 1 but bidders may not want to base their price on a fixed energy payment, preferring instead to price energy based on a fuel index. This could discourage bids from third-parties who do not wish to absorb the cost associated with hedging fuel prices or who have to manage a possible disconnect between the actual fuel cost and the allowable pricing formula.

- As noted, Merrimack Energy will be developing test bids and using these bids to test the modeling methodologies for accuracy and reasonableness.

- For those resource alternatives which involve Company ownership and operation of the projects, an accurate comparison of those proposals with other third-party options will involve a reasonable set of input forecasts of key cost items for the Company ownership options such as fixed and variable O&M costs, start-up costs, fuel costs, and fuel transportation. While these projects will ultimately be treated as cost of service options, to undertake a reasonable evaluation of bids will require preparation of the input assumptions for the company owned and operated units prior to receipt of bids. The IE feels strongly that PacifiCorp should prepare forecasts of such costs before bids are due and provide the forecasts to the IE for a "reasonableness" check before adopting such forecasts in the evaluation.

Credit Issues

Credit considerations in competitive bidding processes have been evolving with each new RFP issued. The approach proposed by PacifiCorp to develop a credit matrix for purposes of determining the credit assurance requirements that a bidder must post based on the size of the project and the credit rating of the bidder is a new approach in the industry. In response to Request Set 1, Question 44, PacifiCorp indicated that the Credit Matrix is modeled after the Moody's Cumulative Default Rates matrix, which identifies corporate default probabilities over a range of credit ratings and time horizons. In the IE's view, the Credit Matrix may be a potentially effective approach to identify the exposure to the buyer and the amount of credit assurance required based on the size of the project and the credit rating of the bidders which have other corporate activities that contribute to default risk. It is not, however, clear that the approach is well suited for special purpose entities which have been advanced adequate development funding and which have no activities other than the single project being financed and constructed based on the creditworthiness PacifiCorp.

Alternatively, other utilities have developed a similar credit matrix based on credit rating and project size but used such a matrix for the non-price scoring of projects. For example, Hydro-Quebec allocates 10% of its total scoring on the basis of a credit matrix it uses to evaluate bids. In general, bidders with higher credit ratings and smaller sized projects will receive a high score (i.e. 10 out of 10), while proposals from non-investment grade entities with larger sized proposals may receive no points.

The concept behind the credit matrix needs further assessment by the industry.. Pending that review, there are other issues associated with the credit requirements outlined by PacifiCorp that need to be addressed based on the IE's assessment and comments of other parties. These include: (1) the level of credit assurance required; (2) the type of security required; (3) whether or not it is reasonable for PacifiCorp to reject bids that subject the Company to accounting or tax treatment that results from a Variable Interest Entity.

A. Level of Credit Assurance Required

The level of credit assurance required based on the values contained in the credit matrix are reported to be based on the total replacement costs for power (without netting out the contract price) for two summers (assuming default) for a PPA and one summer for an APSA. While the discussion of contract issues below gets into more details about the conceptual soundness of the credit assurance levels for each type of resource alternative, this section of the report will compare the magnitude of the resulting credit assurance levels contained in the Credit Matrix with other recent RFPs as a means of undertaking a "reasonableness" check..

There are several observations which can be made upon review of the Credit Matrix. First, the credit assurances required for a PPA is much higher than for an APSA. Furthermore, even bidders with an investment grade rating have to post significant levels of credit assurance if proposing a PPA based on a larger size project. Second, the level of credit assurance required in combination with the size of the proposal, results in an incentive to bid a smaller sized project if one is bidding a PPA relative to an asset based alternative. However, it is more difficult for a smaller size proposal (if based on the construction of a new unit to support the PPA) to compete against a larger asset purchase or EPC option. Thus, based on these restrictions, there is a bias against similar sized PPA options. Third, the level of credit assurance required for an investment grade company bidding a large sized project is very high relative to industry standards. For example, an A/A2 credit rated company proposing a 525 MW PPA would be required to post security of $259/kW, which is extremely high by industry standards. Even companies with a credit rating one notch above investment grade have to post credit assurance in the amount of $430/kW. Based on the proposed methodology, it appears that PacifiCorp has abandoned general principles of contract "cover" damages in assessing its risk exposure. See: (VIII) Assessment of the Contract Issues, Section 11, Credit Requirement Algorithms. From this starting point, PacifiCorp reaches levels of security at variance with industry norms.

In comparison, in recent RFPs, Public Service of Colorado required security of $125/kW. Georgia Power required operating security of $380/kW but only one-half of that amount if the counterparty is an investment grade company. The level of credit assurance required by other utilities varied but in all cases the levels required by PacifiCorp were at the high end of the spectrum. The result of these high levels of security, even for an investment grade entity, is that bidders will be required to increase their price to account for the increase in cost to pay for the credit assurances required.

B. Form of Security

PacifiCorp requires credit support security in the form of a guarantee, letter of credit or cash. NIPPC's position (see Page 2 of the Comments of the Northwest Independent Power Producers Coalition on PacifiCorp's Draft Request for Proposals 2009) is that "PacifiCorp's imposition of a guaranty or letter of credit requirement in an unreachable amount as the exclusive method of satisfying credit criteria is unreasonable and unduly discriminatory". NIPPC also claims that there are a number of credit support mechanisms other than guarantees and letters of credit that have been successfully used by independent power producers and accepted by utilities or load serving entities.

In terms of the form of security, the IE has found upon review of other RFPs and model power contracts for the utilities in the sample chosen that it is standard for utilities to require primary security in the form of a guaranty, letter of credit or cash. While the level of credit assurance required is higher than industry standards, the form of security required by PacifiCorp is consistent with industry standards.

C. Requirements for Variable Interest Entity

PacifiCorp's RFP prohibits participation by parties known as Variable Interest Entities (VIE) in the RFP process. NIPPC takes exception to this requirement. NIPPC recommends that VIEs be considered in the RFP process and that any adverse cost effects of VIE treatment, after considering the capital structure and projected earnings profile of the VIE, be taken into account alongside the overall costs and benefits of the utility self-build options and other proposals (see Page 3 of NIPPC's comments).

Based on the IE's review of other RFP processes, it is becoming more commonplace for utilities to exclude any proposals that would trigger Variable Interest Entity treatment. Based on that review, PacifiCorp's requirement to exclude proposals that trigger VIE treatment is not unreasonable given the uncertainty associated with the implications of VIE on utility accounting and taxes. Since the Edison Electric Institute (EEI) views VIE treatment as more of a concern for bidders proposing Tolling Service Agreements, it is reiterated here that the IE recommends that bidders with PPA resources be allowed to specify a fuel price and/or fuel index as the basis for the fuel commodity price. See: (VII) Economic Evaluation and Models, (D) Conclusions and Recommendations.

Accounting Implications and Debt Impacts

One of the most controversial issues in the competitive bidding process remains the application of inferred and direct debt attributed to power purchase agreements classified as leases on the utility's balance sheet as a cost associated with the evaluation of proposals. While this issue is gaining widespread attention in the utility industry and at the state regulatory level, there is no uniform agreement at the regulatory level yet on the application of inferred debt. Furthermore, there is also uncertainty regarding the appropriate mechanism for assessing the risk associated with various resource options. The positions of the parties to this proceeding differ significantly with regard to the appropriate method for evaluating different types of proposals in the bid evaluation process. As IE, Merrimack Energy is most concerned with ensuring a methodology is in place to evaluate all bids in a fair and equitable manner with no undue biases favoring one resource alternative over another.

PacifiCorp states in the RFP that "all contracts proposed to be entered into as a result of this RFP 2009 will be assessed by the Company for appropriate accounting and/or tax treatment". PacifiCorp describes the basis for determining the accounting treatment of each proposal, the methodology underlying how the costs will be evaluated in the economic analysis in the initial screening, the assumptions used in assessing the impacts of capital or operating lease treatment, and the information required of bidders in submitting their proposals. From a fairness and transparency perspective, the inclusion of such information is a positive improvement over the 2003 RFP. Bidders at least know how their proposals will be evaluated and can reflect this information in making the decision regarding the type of resource alternative and contract structure to propose. Furthermore, PacifiCorp has given the bidders a number of alternatives to consider. The IE feels PacifiCorp has made significant strides in identifying and developing a comprehensive process for assessing the impacts associated with accounting and tax treatment for various contract structures.[1]

While PacifiCorp has made significant strides in developing a fair process, the issue of bias remains with regard to the resource selection process. A key issue is whether the economic evaluation process will result in the evaluation of all types of bids on an equal footing or if undue bias exists favoring a particular type of resource. In essence, does an asset ownership or EPC option enjoy an undue competitive advantage over a PPA as a result of the application of accounting and tax treatment that may contain an undue bias. While Independent Power Producer interests admit that Credit Rating Agencies apply a debt equivalence factor to utilities that purchase power under PPAs they execute with competitive power suppliers, (see Electric Power Supply Association; Electric Utility Resource Planning: The Role of Competitive Procurement and Debt Equivalency, June 2005, page 5) Rating Agencies also consider the financial impacts of rate base plants on the utility's capital structure. Several parties in this proceeding have weighed in on this issue.

In its comments in this proceeding, the Division of Public Utilities raises concerns about PacifiCorp's approach with regard to the screening evaluation used to arrive at a short-list of bids relative to the inclusion of inferred and/or direct debt in the evaluation. The Division refers to the testimony of Dr. William (Artie) Powell on this issue in Docket No. 03-035-14. As stated in its comments, the Division raises some concerns with regard to the appropriate methodology for evaluating resource alternatives and renders a suggestion with the regard to the risk factor which should be applied:

> In brief, the Division argued that, while rating agencies view certain contracts as imposing costs on the utility and impute debt to the utility's balance sheet for rating purposes, the actual impact or affect of this action on the utility's cost of capital is uncertain. Indeed two reports cited by the Division in its testimony conclude that little or no empirical evidence exists to support the hypothesis that the utility's cost of capital is adversely affected by the debt imputation. Furthermore, both Moody's and Standard & Poor's indicate that mitigating factors could result in a lower debt imputation. For example, Standard & Poor's indicates that the passage of SB26 may result in a lower risk factor – 30% instead of 50% - being applied in determining the amount of debt to impute. Based on these two factors, little or no empirical support and the stated rating policies of Moody's and Standard & Poor's, the Division recommended the use of a conservative 15% risk factor. We restate this recommendation for use in the screening evaluation of bids in the current RFP.

1 The IE has a continuing question about the correct calculation of the cost of the equity infusion needed to re-balance the balance sheet of PacifiCorp. See: Response to Independent Evaluator Data Request 1.6, wherein PacifiCorp uses a reduced amount of equity to retire existing debt which had a cost of debt equal to the weighted average cost of debt (7.00%). It is unclear why the highest cost debt would not in this case be retired.

> Additionally, the Division is concerned about the effect of a self-build option. Several sources cited by the Division in its testimony in Docket No. 03-035-14 conclude that a utility's self-build option poses more risk in terms of the utility's cost of capital than does power purchase agreements. For example, in the report prepared at the Lawrence Berkeley Laboratory the authors conclude, "At least as far as the cost of equity is concerned, we find more evidence to support the notion that utility construction raises the cost of capital than that NUG [non-utility generation] purchases do. One potential solution to this dilemma is offered by the Electric Power Supply Association:
>
> > [An] approach is to apply a risk premium to the cost-plus offer in the evaluation of bids. The risk premium could be based on historical experience on cost pass-throughs [i.e. cost over-runs] with similar technologies. For example, if cost-passthroughs raised rate base by 20 percent in the past, the capacity related price in the cost-plus bid would be raised by 20 percent for purposes of bid evaluation (see pages 3-4).

The Northwest Independent Power Producers Coalition (NIPPC) also submitted comments on the debt issue. NIPPC's position is that "the Commission should endeavor to remove bias in the bid evaluation process in regard to "inferred debt" and to provide symmetry between competing proposals and the utility self-build option, as far as the evaluative process is concerned".

> The application of debt-equivalency and a risk factor of 50 percent in the bid evaluation process fails to consider the salutary effect of S.B. 26, enacted during the 2005 General Session of the Utah Legislature. This bill provides the necessary assurance for cost recovery on investments in "significant energy resource decisions," such as those associated with long-term PPAs, whose costs have been found to be prudent and approved by the Commission. The law renders null the need for application of a 50 percent risk factor on a long-term PPA. Finally, in the absence of a comparable evaluation of the risks and costs associated with the utility self-build option, it will render the competitive proposal under the RFP too expensive for further consideration.
>
> From a cost-recovery standpoint, the debt-like risk of PPAs should not create more financial exposure for the utility customer than the debt and equity risk of utility-sponsored power plants. The reason is that state approval for PPA cost recovery has been generally consistent and certain for the past 20 years. Imposing debt-like risks on PPAs during the competitive bidding process, but not on the utility-sponsored self-build or own option, creates an unfair bias that can mask the true benefits to consumers of the PPA option. Among those benefits is the fact that PPAs provide a measure of protection for utility customers and shareholders alike, because neither party assumes the risk of contract non-performance – that risk is transferred to the PPA sponsor's owners and shareholders.
>
> NIPPC believes that PacifiCorp's proposed treatment of inferred debt, or debt-equivalency, should only be applied in the context of a comprehensive review of the costs, risks and benefits of all resource options, including the utility's self-build option. (See pages 6-7)

NIPPC identifies five options with regard to inferred debt that the Commission should consider:

- Strike this section from the RFP;
- Reduce the risk factor to a maximum of 10 percent, which more accurately reflects Standard & Poors' current thinking in regard to the application of risk factors;
- Ensure comparable assessment of all risks and costs of both the competitive proposals under the RFP and any proposed PacifiCorp self-build alternative during the bid evaluation process;
- Consider the provision of a return on the PPA "asset" for PacifiCorp, since it will be managing the performance of the contract, similar to what it does for the performance of its own power plants; or
- Consider the imposition of additional equity in the context of a PacifiCorp cost-of-capital proceeding, where all of the utility's risks and costs can be considered on a broader basis, rather than in this single bid evaluation.

With regard to the above options, the third option has some merit if it can be demonstrated that utility self-build construction projects or asset purchases have historically resulted in an increase in the cost of capital of the utility that can be segregated from changes resulting from more general economic factors such as rising or falling interest rates. However, NIPPC has not provided any background studies or documentation identifying an appropriate or reasonable cost of capital increment to be added to the cost of a self-build option in the bid evaluation process. Furthermore, the IE is not aware of any studies or regulatory proceedings in which such an adjustment has been implemented in a power procurement evaluation process.[2]

Also, the fifth option basically accomplishes the same impact on the utility's balance sheet as including inferred debt in the bid evaluation process. The difference is that the impact of a PPA is accounted for in a cost of capital proceeding rather than in the evaluation process, and that impact, if assessed and known earlier, might have resulted in a change in the evaluation and selection of bids.

The IE believes that any decision regarding the treatment of inferred debt on the utility's balance sheet associated with PPA options should be based as nearly as possible on the principles of unbiased scoring. In this regard, the viable options appear to be the following:

- The development of an estimate of the expected increase, if any, in PacifiCorp's cost of capital due to the selection of a self-build or asset purchase option and quantification of the impacts of that increase so that both the cost impacts of direct and indirect debt on the cost of capital and the cost impacts of rate based assets are included in the scoring.

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2 The IE has identified another possible adjustment necessary to put PPAs and self-build options on a more equal footing. While the rating agencies include the fixed costs of certain PPA's on the utility's balance sheet for purposes of assessing risk and rating the utility, there has been no mention about fixed cost exposure associated with utility self-build options. For example, a self-build option may contract for long-term firm pipeline capacity of other long-term fuel contracts. These contracts impose a risk on the utility as well that debt-like treatment will result since such costs may be absorbed no matter the condition of the project. It may be necessary, as a matter of fairness, to impute the extra cost of any equity infusion related to such fixed costs as a premium in the cost structure of the self build options.

- A review and assessment by the Commission concerning the appropriate treatment of inferred debt on the utility's balance sheet.

Although the IE feels that these issues apply nationwide to the electric utility industry and should be assessed on such a level, a review and assessment by the Commission regarding the appropriate approach for evaluating different resource options may be required. The Commission should state (i) what evidence will be required from rating agencies or other sources in order to demonstrate that infusing equity as proposed is lower in cost than the increase in the cost of debt and equity capital that can reasonably be expected to ensue if the capital structure is not restored and (ii) what alternatives must be considered, such as alternative regulatory mechanisms, in order to demonstrate that equity infusion represents the impact on the Company's cost of capital which is the "lowest reasonable cost". In the latter regard, for example, "cost trackers" in the form of well understood competitive power adjustment clauses and fuel cost or fuel price clauses have often been cited by both rating agencies and regulatory research institutions as mechanisms that improve credit metrics and stabilize utility capital costs. A comparison might be called for of the long run cost impacts of adjustment clause rate-making for PPAs versus the long run cost impacts of a capital structure with equity supplements which re-balance accounting or equivalent debt.

In principle, the relevant inquiry concerning "lowest reasonable cost" for any eligible resource would not be limited to PPAs. "Lowest reasonable cost" includes the cost of capital and the Commission is a primary actor in the determination how the public interest should be applied to determine or to affect the cost of capital. After the legislative determinations in S.B. 26, a regulatory objective consistent with S.B. 26 would be to design rate-making procedures which maximize the likelihood that PacifiCorp would experience no adverse cost of capital consequences on account of its procurement of competitive power, whether the competitively selected resource were a rate base asset or a purchased power agreement.

VIII. Assessment of the Contract Issues

The IE has undertaken an assessment of the forms of model contracts contained in the RFP to assess whether there are any undue biases in the form contracts that could favor one type of resource option over another. The sections below provide a discussion of several key provisions of the PPA and APSA agreements for comparative purposes.

A. Risk Allocation between Seller and Buyer in Contractual Forms: Issue by Issue Comparison between Power Purchase Agreement (PPA) (Attachment 3) and Asset Purchase and Sale Agreement (APSA) (Attachment 6)[3]

3 The Tolling Service Agreement (TSA) shares a common foundation in the forms and can be described as a PPA without gas service. The Engineering, Construction and Procurement Contract (EPC) shares a common foundation in the forms with the APSA and can be described as an APSA without the development and permitting duties. For purposes of brevity, a comparison of the PPA and the APSA should be sufficient to illustrate the salient differences

1. Force Majeure Exclusion of Permits. In Section 1.1 of the PPA, the Force Majeure definition in Section 13.1 is cross-referenced. In Section 13.1, Force Majeure is defined explicitly to exclude "(v) delay or failure of [Seller][4] to obtain any Required Facility Document." Required Facility Document is defined in Section 1.1 to include all Permits and agreements necessary for development, construction, operation and maintenance of the Facility. Accordingly, delay or failure of Seller to obtain its required permits is not an event of Force Majeure excusing a delay or failure of Seller to meet its Milestone duties under Section 2.2. Such a Milestone failure can then mature into a Seller Event of Default under Section 10.1.2.4 and 10.1.2.5.

   In contrast, under the APSA, the definition of Force Majeure in Appendix F contains important differences more favorable to Seller. An exclusion is first stated but then qualified as follows: Force Majuere excludes "(iii) delay or failure by the Seller to obtain any Governmental Approval, all of which should have been anticipated by the Seller in connection with Seller's reply to the RFP, other than the delay or failure to obtain Governmental Approvals occasioned by (x) revocation, stay, or similar action by a Governmental Authority of a Governmental Approval after issuance thereof by a Governmental Authority, (y) the failure of a Governmental Authority to comply with rules, procedures or Requirements of Law applicable to such Governmental Authority or (z) another Force Majeure." The exceptions to the exclusion mean that time-consuming appeals, governmental miscues and other Force Majuere events causing permit delay or failure may result in excused permit failures. Importantly, "Permits", defined in Section 7.36 to include "all applicable construction and construction related permits" are not within the exclusion from Force Majeure.

   Accordingly, APSA Sellers fare significantly better in avoiding the risk of defaults due to delays in obtaining permits than do PPA Sellers which are entitled to no relief from Milestone failures due to permit delay[5]. APSA Buyers experience higher risks of

between the two categories of forms: third party product delivery and service agreements (PPAs and TSAs) and owner asset procurement and acquisition agreements (APSAs and EPCs).

4 Upon inquiry, Senior Counsel to the Company informed the Independent Evaluator that the form in Attachment 3 contained a typographical error and Seller is intended to replace Buyer in subclause (v) of Section 13.1.

5 Curiously, PacifiCorp's standard form QF contract shows tolerance for permit delays similar to the tolerance unilaterally extended in the 2009 RFP Contract Forms only to the APSA resource. See: Section 13.1 of FORM OF POWER PURCHASE AGREEMENT [QUALIFYING FACILITIES IN EXCESS OF 1000 KILOWATT NET OUTPUT] (Force Majuere includes "other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which is in each case (i) beyond the reasonable control of a party, (ii) by the exercise of reasonable foresight such party could not reasonably have been expected to avoid and (iii) by the exercise of due diligence, such party shall be unable to prevent or overcome.") Attachment A to this Report contains a copy of the subject QF FORM. For comparison purposes, see: MODEL DISPATCHABLE POWER PURCHASE AGREEMENT of Public Service Company of Colorado (distributed in connection with the Xcel 2005 All-Source RFP), in which in Section 14.1, Force Majeure is defined to include "actions by any Governmental Authority taken after the date hereof (including the adoption or change in any rule or regulation or environmental constraints lawfully imposed by such Governmental Authority) but only if such requirements, actions, or failures to act prevent or delay performance; and inability, despite due diligence, to obtain any licenses, permits, or approvals required by any Governmental Authority". Attachment B to this Report provides a short list of terms and conditions of the Xcel

uncompensated delays and cost increases as a result of the flexibility in performance accorded APSA Sellers. See: Comment No. 4, infra.

2. General Force Majeure Standard. In Appendix F of the APSA, Force Majeure is defined with reference to a general standard, "an event not reasonably anticipated as of the date of this Agreement". In contrast, Force Majeure is defined in Section 13.1 of the PPA as "an event . . not anticipated as of the date of this Agreement. As a result of this difference, it is easier to qualify as an event of Force Majeure under the APSA than under the PPA. In general, APSA Buyers face a higher risk of uncompensated delays or increased costs due to the increased flexibility in performance accorded APSA Sellers under the Force Majeure clause.

3. Force Majeure Exclusion of Required Facility Documents. As indicated above, delay or failure of Seller under the PPA in obtaining any Required Facility Document is not an event of Force Majeure. In Section 1.1, Required Facility Documents include all financing related agreements, such as the lender consent and intercreditor and subordination agreements which the Company expects to execute[6]. While the Company's actions affect the ability of Seller to obtain such financing documents, Seller under the PPA remains at risk, without Force Majeure excuse, for any delay in satisfying its Milestones duties under Section 2.2. Such a Milestone failure can then mature into a Seller Event of Default under Section 10.1.2.4 and 10.1.2.5.

   The timely completion of comparable Transaction Documents, defined in Appendix F of the APSA, appear to be Seller's responsibility under various provisions of Section 4, Section 10.6, and Section 17.1(b)(v) of the APSA. However, delays in obtaining Transaction Documents are not excluded from the APSA Force Majeure definition. Moreover, any delay in issuance of the Notice to Proceed due to delays in Transaction Documents requires Seller to submit an updated version of the Project Schedule under Section 10.1. The procedure for rejection of updated schedules in Section 10.3(a) (treated as a "Buyer-Initiated Change" under Section 13.1) may not ultimately result in Seller accountability for the document delays[7].

   Accordingly, APSA Sellers fare significantly better in avoiding the risk of defaults due to delays in obtaining Transaction Documents than do PPA Sellers which are entitled to no relief from Milestone failures due to Sellers' delay in obtaining Required Facility Documents. APSA Buyers experience higher risks of uncompensated delays and cost increases as a result of the flexibility in performance accorded APSA Sellers. See: Comment No. 4, infra.

Model PPA, showing balance between buyers and sellers not present in the PPA here.

6 See Response to IE Data Request 1.38.

7 Seller accountability for failure to obtain Governmental Approvals and Permits under the APSA, even when it is clear that no Force Majeure excuse is applicable, is likewise subject to doubt due to the Project Schedule revision process in Section 10 of the APSA. The APSA Form exhibits ambiguity that may have been the intentional result of actual negotiations that affect the Form.

4. Force Majeure and Change in Law Cost Increases. The Company has acknowledged that the applicable provisions of the EPC and APSA result in a risk that costs to Buyer under the APSA may increase to reflect certain Force Majeure and Change in Law events or occurrences. In light of the well-understood fixed pricing provisions of the PPA, no comparable risk exists for Buyer under the PPA. Responses to IE Data Requests 1.46 and 1.48. Compare: Sections 5.1.2 and 6.3.1.1 of the PPA to Sections 10.1, 10.3(a), 13.2(b), 13.2(c), and 28.3 of the APSA.

5. Milestone and Development Risk. Both PPA Sellers and APSA Sellers have duties to meet applicable Milestones and achieve completion of the Facility or face contract consequences for delays or failures in performance. See: Sections 2.2, 2.3, 10.1.2.4, 10.1.2.5 and 10.2 of the PPA and Sections 7.5, 7.36, 10.6, 17.1(b), 17.2, 24.2, 24.3, 29.1(a), 29.4 and 30.1(b). However, APSA Sellers enjoy more flexibility in their performance than do PPA Sellers due to differences in the Force Majeure, scheduling and permit provisions of the subject forms.

   Moreover, PPA Sellers face a “no notice and no opportunity to cure” risk of termination for any delay in obtaining the Commercial Operation Date (Section 10.1.2.5) and can get little meaningful relief from such risk from the Force Majeure provisions dealing with permits and required documentation. On the other hand, APSA Sellers do not face a comparable “no notice and no opportunity to cure” risk of termination when the deadline for Substantial Completion is missed (Sections 29.1(a) and 30.1(b)(ii)) and, in any event, can get substantial relief from such risk in the Force Majeure and scheduling provisions of the APSA. See: Comments No. 1-3; Response to IE Data Request 1.36.

   Accordingly, the risk of milestone and development default and termination is significantly higher for PPA Sellers than for APSA Sellers.

6. Delay Damages. Under Section 2.3 of the PPA, Seller is required to pay defined Daily Delay Damages if the Commercial Operation Date occurs after the guaranteed date. The damages are defined with reference to the market price of power at a specified location. The measure of daily damages does not, however, bear any relationship, at least in concept, to contractual damages which are limited to the difference between the replacement cost of power and the contract price. Here, the gross price of power is the measure of the daily stipend. Day for Day, then, the PPA delay damages are overstated.

   Under Sections 24.2(c) and 24.3 of the APSA, Seller is required to pay daily Critical Milestone liquidated damages and daily Late Substantial Completion LDs ($50,000 per day for dispatchable Projects), respectively. Since the product being delivered under the APSA is a Facility, damages are not calculated in terms of replacement power costs, but rather in terms of the extra carrying costs incurred by Buyer due to the delay in delivery and operation of the purchased asset.

   It is the understanding of the IE that daily damages for PPA Sellers are expected to be significantly higher, day for day, than daily damages for APSA Sellers.

7. Capital Cost Escalation. Under Sections 5.1.2 and 6.3.1.1 of the PPA, payments to PPA Sellers are not allowed to increase for any reason, including, as indicated above in Comment

No. 4, for reasons of Force Majeure or Change in Law. This applies equally during before and after the Commercial Operation Date.

Sections 10.1, 10.3(a), 13.2(b), 13.2(c), and 28.3 of the APSA may, under certain circumstances, result in capital cost increases to APSA Buyers. Other events during the Term of the APSA could cause a change in the Scope of Work, as defined in Appendix F, and potentially, an increase in the final capital cost incurred by APSA Buyers. Like most construction-based contractual forms, the APSA contains Change Order procedures which contemplate price and other adjustment to the original contract terms (e.g., see: Section 7.21 (Spare Parts available by Change Order); Section 10.3 (Buyer Initiated Change when Buyer rejects an updated Seller Project Schedule); Sections 13.1(c)(iii), 13.2(b), 13.2(c)(i) (Change in Applicable Law/Permit or Site Condition), 13.2(c)(ii) (Suspension of Work by Buyer), and 13.2(c)(iii) (Non-Performance by Buyer). Additionally, a failure of Buyer to meet its schedule obligations under Section 10.2 can lead to delays and cost increases under Section 10.8(d). During operation of APSA resources by APSA Buyers, capital additions and retrofits would, except for warranty items, be at the risk and cost of APSA Buyers[8].

Accordingly, APSA Buyers are exposed to risks of capital cost increases, both before and after the Commercial Operation Date, which are simply not applicable to PPA Buyers.

8. Unavailability and Replacement Power Costs. During the portion of the PPA Term after the Commercial Operation Date, PPA Sellers are exposed to the risk of reductions in their Capacity Payments under Section 5.1.2 to the extent of their monthly unexcused hours of unavailability exceed allowed margins. See: Response to IE Data Request 1.50. Defined Events of Default create additional risk of default and termination for unexcused unavailability by PPA Sellers (Sections 10.1.2.2, 10.1.2.8). Payment reductions flow to the benefit of PPA Buyers which can use the savings to fund the cost of replacement power. When termination results from unavailability defaults, PPA Sellers are exposed, under Section 10.7, to conventional contractual cover damages requiring termination payments calculated to cover, for the remainder of the Term, the difference between the defined Replacement Price for energy and the price per MWH specified in Exhibit F to the PPA[9].

   Conversely, except for warranty defects enforced during the applicable warranty period (18 months in most cases) (see: Article 23), no comparable risks for unavailability problems during operation of the Project exist for APSA Sellers. By its terms, the APSA has been performed and is not longer in effect when the majority of the operating period under the PPA is occurring. In general, APSA Sellers bear no risk for replacement power costs since the product delivered under the APSA is a completed Project asset and not a power commodity over a period of years. See: Section 6.2(b) of the APSA where the APSA Seller's primary liability for direct damages is described as the payment of the defined Net

8 Capital additions and retrofits or repairs outside of the Company's "most probable estimate" of expected costs would not even be taken into account in the scoring of APSA resources in comparison to PPA resources. Response to Independent Evaluator Data Request 1.18.

9 Since Exhibit F to the PPA contains only the Energy Payment required under Section 5.2, a question immediately arises whether the Section 10.7 correctly calculates conventional cover damages or incorrectly fails to give appropriate credit to Seller for the Capacity Payment component of the contract price. In the latter event, Section 10.7 could readily be challenged.

Replacement Cost – the excess costs incurred by Buyer to complete the Project after terminating Seller. See also: Section 29.4 where Buyer's spectrum of remedial rights and damages are set forth, none of which includes the obligation to cover the excess replacement cost of power.

Accordingly, APSA Sellers are exposed to little, if any, risk of replacement power costs and APSA Buyers have little, if any, protection from the risk of incurring full replacement power costs for their own account[10]. On the other hand, PPA Sellers have a significant risk of payment reductions designed to contribute to replacement power costs and of termination liability calculated to provide full cover damages for the unexpired remainder of the Term of the PPA. PPA Buyers have corresponding protection from replacement power costs.

9. Energy Cost Escalation. Under the present provisions of Section 5.2 and Exhibit F to the PPA, PPA Sellers are restricted to bidding Energy Payment formulae that conform to inflation-based indices. In turn, PPA Buyers would benefit from important risk protection from fuel-based escalation indices in current and future fuel markets which, for the reasonably foreseeable future, may be extremely volatile. Conversely, as asset owners, APSA Buyers will be exposed to the full risk of fuel market escalation[11]. APSA Sellers have no role in fuel purchasing which occurs after their performance is complete.

10. Fuel Interconnection Costs. The cost of the fuel interconnection for the Projects is one aspect of the capital cost of the Projects. As such, comments set forth in Comment No. 7 are equally applicable to fuel cost increases that are experience after the Effective Date of the PPA or the APSA. Under Sections 5.1.2 and 6.3.1.1 of the PPA, payments to PPA Sellers are not allowed to increase for any reason, including, for any change in the scope of the fuel interconnection. Such changes could, however, result in capital cost increases to APSA Buyers.

11. Credit Requirement Algorithms. Under Section 7 of the PPA and Article 6 of the APSA, PPA Sellers and APSA Sellers, respectively, must provide credit assurances in accordance with a Credit Matrix developed by the Credit Department of the Company (Exhibit C to the RFP). The Credit Matrix differentiates among Sellers depending upon the type of resource, the size of the resource and the credit rating of Sellers.

    PPA and TSA Sellers have the same credit requirements which start sooner and escalated higher, relative to project size, and relative to declining credit rating, than comparable requirements for APSA and EPC Sellers. In fact, for PPA and TSA Sellers with BBB- or lower credit ratings, the credit requirement, at each Project size, is exactly double the

10 In light of the language in 17-54-201(2)(c) requiring consideration during the solicitation approval process of the interests of both retail customers and the financial health of the affected electrical utility, the IE makes no distinction whether the risks experienced by Buyers under PPAs and APSAs are ultimately borne by ratemaking rules or mechanics by the shareholders or the customers of the utility.

11 By ratemaking convention (net power cost modeling), Buyer's customers will experience much of the actual fuel escalation and Buyer's shareholders will share in exposure to fuel price changes between rate cases which vary from the fuel escalation modeling done at the time rates are set. For purposes of this analysis of contract risks, the IE does not distinguish between Buyer risks actually experienced by customers and Buyer risks actually experienced by shareholders.

required amounts for similarly rated APSA and EPC Sellers. For a paradigm 525 MW Project, the credit assurance requirement for a BBB- rated PPA Seller is $324,507,750. The comparable requirement for a BBB- rated APSA Seller with a 525 MW Project is $162,253,875.

The underlying damage calculation performed by the Company determines the gross replacement power cost for two summers of replacement power costs for PPAs and TSAs and one summer of such costs for APSAs and EPCs. See: Response to IE Data Requests 1.41. It is the understanding of the IE that such amounts coincidentally approximate the calculation of conventional cover damages (replacement power costs less contract price[12]) for a 300 MW Project for a full Term of 20 years.

The stated basis for the calculation of the credit assurance (gross replacement power costs) amounts bears no conceptual relationship, in legal theory, to conventional contractual cover damages[13]. For the APSA, this disconnection is complete since APSA Sellers are not, in any event, liable for cover damages based on replacement power costs. See: Section 6.2(b) for a statement of the conventional liability of an asset contractor.

For PPA Sellers, the IE expects that credit assurance requirements in the proposed amounts will add significant costs to PPA bids. For APSA Sellers, it is expected that the added costs will be lower for two reasons. First, the required amounts are lower. Secondly, since liability under the APSA cannot be established on the basis used for calculating the required amounts, a larger pool of creditworthy guarantors is more likely to be found which guarantors will be willing to take the lower risk of potential damages that is actually represented by the overall set of risks on APSA Sellers under the APSA terms and conditions.

12. Credit Requirements and Industry Norms. See: (VII) Credit Issues, (A) Level of Credit Assurance Required, above.

13. Credit Requirements and Project Specific Considerations. The Company's credit methodology takes into account its determination of damage exposure (described above in Comment No. 11) and its assessment of the risk of contract default represented by counterparties with specific credit ratings or no credit rating. The Company's methodology takes no account of (i) differences in risk levels, if any, between the development period of PPA performance and the operating period of PPA performance[14], (ii) any changes in the assessment of default risk over the term of the subject agreements based on the stage of the

12 The IE is not certain how the cover damages were actually calculated and in this regard, whether Sellers under the PPA received credit for the full contract price, including Capacity Payments under Section 5.1.2.
13 Credit assurance determinations typically reflect two factors: (1) the extent of the party's exposure to contractual damages when its counterparty defaults and the contract is terminated and (2) the risk that the counterparty will actually default (based on its creditworthiness) and expose the party to the subject contractual damages. The IE is unfamiliar with any assessment of the second risk factor which results in a risk assessment as high as 300/525ths of the total damage exposure, i.e., a 57% probability that the counterparty will default and cause a loss of 100% of the contract value.
14 Response to Independent Evaluator Data Request 1.41.

Project[15], (iii) assurances of funding to APSA Sellers and PPA Sellers from the Company's progress payments and from draws on committed construction lenders, respectively[16], and (iv) project specific development and financing through bankruptcy-remote special purpose entities[17]. In the last regard, the use of corporate default probabilities in the Credit Matrix seems to be premised on the counterparty being engaged in other corporate activities which contribute to default risk under the subject power purchase agreement with PacifiCorp.

Other utility buyers under long term power purchase agreements have taken into consideration project-specific risks and have distinguished levels of non-completion risk based upon the stage of project development. Such assessments consider, among others factors, (1) the relatively higher levels of non-completion risk at early development stages before permits are obtained, fuel and fuel transportation are assured, interconnection is assessed and contracted, equipment and contractors have been engaged and financing is achieved; (2) the progressive decline in non-completion risk as each prerequisite to construction financing is satisfied; (3) the relatively low level of non-completion risk for a bankruptcy-remote special purpose entity upon construction financing and the commitment of lenders and/or creditworthy investors to fund fixed price construction agreements and other fixed or reliably estimated completion costs; and (4) the historically low level of non-performance default risk during operation using conventional generation technologies and experienced operators subject to performance requirements within warranted and/or historically proven levels of performance.

In addition to risk assessments which depend on specific project parameters at different stages, some power buyers have assessed non-completion damages in terms of likely outcomes and likely mitigation. In this regard, higher risk failures are likely in early development and would be mitigated with replacement projects which trail the failed projects into service by a limited number of years. For such years, cover damages are required based on the difference of replacement power costs and contract power costs. Additional damages may be determined if fuel or capital cost pricing for the replacement plant are expected to vary from the fuel and capital cost pricing of the failed project, a result that does not always apply given recent capital costs and fuel pricing mechanisms[18].

Credit requirements which reflect project specific risks and likely default outcomes are generally much lower than the Company's credit requirements, resulting in larger pools of potential bidders and at the least the potential of correspondingly lower bids.

14. Lender Rights and Coordination. Other than a milestone requirement in Section 2.2.3 for construction financing, only one reference to role of lenders in connection with a Project is

15 Response to Independent Evaluator Data Request 1.42 (changes will be made for changes in the credit rating, however.) Curiously, the Company's Qualifying Facility standard form PPA, Attachment A, like PPA forms for many other utilities, contains references to Development Security and Default Security. The IE is unaware of the levels of security demanded of QFs and how the two types of security may differ.
16 Responses to Independent Evaluator Data Request 1.43 and 1.44.
17 Response to Independent Evaluator Data Request 1.45.
18 Under certain default and mitigation scenarios, collection by the Company of the amounts of credit assurance proposed would appear to represent an uneconomic windfall to the Company in comparison to actual damages after construction of a replacement plant is completed.

set forth in the PPA. In Section 7.2,1, the Security Interests required to be given by PPA Sellers to Buyers are made subordinate in right only to the interests of financiers contemplated by Section 2.2.3 and approved by Buyers. In light of the provision for Progress Payments to APSA Sellers (Article 3), there appear to be no references to lenders or financing parties which apply to APSA Sellers in the APSA.

It is the understanding of the IE that the absence of lender rights and lender coordination provisions in the PPA was intentional. However, the Company acknowledges that in due course, before or after PPA execution, negotiation of lender consent, intercreditor or subordination agreements could result in changes to the PPA or the PPA Buyer's rights and remedies thereunder. Response to Independent Evaluator Data Request 1.38. It is important to note that any delay in such negotiations after execution would be at the risk of PPA Sellers. See: Comment No. 3, above.

Many other utility buyers in their long term power purchase agreements provide conventional lender provisions in their forms[19] and/or are known to negotiate detailed provisions during the finalization of execution version of their power agreements. Such provisions commonly include (i) a Buyer obligation to give lenders notice and opportunity to cure Seller defaults prior to any Buyer remedial action; (ii) agreement by Buyer to enter into, subject to necessary limitations, consents and intercreditor and subordination agreements at the request of lenders; (iii) Seller's right to assign the PPA to lenders for collateral security purposes without Buyer consent; and sometimes (iv) more elaborate recognition of (a) the superiority of lender's rights to those of Buyer with respect to asset security and priority, step-in rights and operational control and (b) the accommodation by Buyer of lender's needs for additional time to obtain possession and cure Seller defaults, and/or for new power agreements with Buyer, in connection with foreclosures on the Project by lenders[20].

Here, based on the present PPA form, PPA Sellers will experience added risk in negotiating these conventional provisions and may have to do so after PPA execution when time needed to meet construction financing milestone deadlines is expiring. See: Section 2.2.3. APSA Sellers experience no comparable risk. Moreover, even the Company's QF form is more accommodating to lenders than the PPA form proposed here. See: Section 19 of Attachment A.

15. Events of Default. Subject to limited relief from the Force Majeure clause, PPA Sellers face an Event of Default if they fail to achieve milestone deadlines, subject to notice and a 30 day opportunity to cure. Section 10.1.2.4. However, of most importance, PPA Sellers, again with little, if any, effective Force Majeure relief, have no opportunity to avoid an Event of Default and to cure a failure to achieve the Commercial Operation Date by the Guaranteed Commercial Operation Date, even if the Facility is then within days of completion.

19 See: Sections 11.2(A), 12.1(B), 12.2, 19.1(B) and 19.2 of Attachment A.
20 The Company supplied the IE with redacted versions of lender consent and subordination forms that had been used by the Company or an affiliate in a recent transaction. Upon review, the IE views these lender forms to be consistent with industry norms. The decision not to include lender provisions in the PPA form is not explained by the nature of the contemplated lender forms.

The Company believes that bidders with sufficient experience, financial position, track record, and other attributes will be able to complete financing and deliver a completed Facility subject to the risk of default and termination of the PPA implicit in such provisions. Response to Independent Evaluator Data Request 1.37. The Company did not otherwise respond to the inquiry what the likely impact on the cost of equity would be due to such provisions. It is the understanding of the IE that the Company believes that performance and default provisions such as these perform a screening function and eliminating undesired bidders.

In comparison, for APSA Sellers, all milestone failures are covered by Section 29.1(a) with notice and a 30 day period to cure. APSA Sellers also face a more favorable Force Majeure provision regarding permit document delays. Furthermore, the provision for Project Schedule revisions in Section 10.1 creates the prospect that milestone deadlines will be flexibly extended notwithstanding prior problems.

Accordingly, PPA Sellers face significantly higher risks of default and termination under the default provisions of the PPA than APSA Seller face under the counterpart provisions of the APSA.

16. Consequential Damages. With no substantive explanation[21], the PPA contains a unilateral ban on consequential damages in favor of PPA Buyers, while the APSA contains a bilateral ban on consequential damages which equally protects APSA Sellers and Buyers. Compare: Section 11.3 of the PPA to Section 25.2 of the APSA.

B. Product Differences as Shown in PPA and APSA Forms:

1. Third Party Delivered Services Agreement vs. Asset Acquisition Agreement. A power purchase agreement for an extended number of years, preceded by development and construction of the Facility dedicated to the subject sales service, captures a markedly different product than an asset acquisition agreement ending after the development and construction of the otherwise comparable Facility. The fact that the Facility may be identical under both agreements is misleading - - the services hired, the product delivered, the standards for performance and the very term of years are all different.

   In simplified terms, the PPA internalizes many risks to which the owner of a power plant would otherwise be exposed. During the development and construction period, the risks of licensing or other development failure, construction mishaps and retrofits, cost overruns and defective or late completion are largely accepted by PPA Sellers and largely avoided by PPA Buyers. At the time of contract execution, prices are fixed or set according to fixed formulae for units of capacity and output and remain unchanged, except for adjustment in accordance with negotiated performance standards, for the contract term. During the operating period, a period which is absent under the asset acquisition agreements, for a price, the risks of capital and fixed and variable cost increases from defects, capital additions and other retrofits or

21 The IE understands that the forms were written in this respect as intended by the Company.

overhauls, routine and major maintenance, taxes, efficiency problems or other operating deficiencies, environmental or other changes in law and in some cases, fuel price changes, are largely accepted by PPA Sellers and largely avoided by PPA Buyers[22]. When termination occurs, damages are determined based on "cover" theories applied to the cost of the replacement product - - power over the unexpired portion of the original term.

The APSA in many ways mirrors the development and construction period of the PPA. During that period, the risks of licensing or other development failure, construction mishaps and retrofits, cost overruns and defective or late completion are also mainly accepted by APSA Sellers and avoided by APSA Buyers. However, in this APSA, as in many others in the industry, the transfer of risk to APSA Sellers is not as complete as in the case of the PPA - - more flexibility and tolerance for force majeure events are shown during construction and development than in the PPA. As well, APSA Buyers become invested in the process, making progress payments and anticipating the likely completion, rather than abandonment, of the Facility, at the cost of defaulting APSA Sellers, when problems arise and the Facility is not completed by the original counterparty at the contract price. Thus, when termination does occur, damages are recovered on "cover" theories, but in this case, "cover" is the excess cost to complete construction as bargained for.

Since no counterpart period of operation is a part of the asset acquisition agreement, APSA Buyers accept all typical incidents and risks of ownership upon completion of the Facility. As owners, the risks of capital and fixed and variable cost increases from unwarranted defects, capital additions and other retrofits or overhauls, routine and major maintenance, taxes, efficiency problems or other operating deficiencies, environmental or other changes in law and in all cases, fuel price changes, are accepted by APSA Buyers. No coverage for replacement power costs is available for the long period of operation after the APSA expires.

2. Expected Differences in PPA and APSA Forms. The PPA and APSA forms in this RFP exhibit expected and largely defensible differences in risk allocation, and bids should show differences in the related pricing, based on the differences which exist in the different products. For additional discussion, please see: Comments (C) and (D), below.

3. Salient Differences in Buyer and Seller Completion Risk. During the development and construction period, the APSA Seller and the APSA Buyer share a joint endeavor to an extent absent in the PPA. There is a balancing of risks regarding development licenses and permits. A process is contemplated to finalize, and then to revise as necessary, the Project Schedule after contract execution. The APSA Buyer makes progress payments toward its acquisition price and the APSA Seller requires a line of credit to advance progress, but no formal construction loan. The APSA anticipates, as well as effects, ownership by the APSA Buyer. The APSA Buyer has accepted terms and agreed to early payments consistent with a progressive vesting of its ownership interest in the Facility. The interests of the owner and the owner's chosen counterparty are more clearly aligned in favor of completing the Facility. Development performance standards and deadlines are less rigid and more accommodating

22 The cost of replacement power during continued operation by PPA Sellers is not explicitly covered; however, performance standards serve to reduce payments required from PPA Buyers, freeing cash to contribute to excess replacement power costs.

of delays outside the control of a non-performing APSA Seller. Higher ownership-type risks are taken by the APSA Buyer in terms of delay and cost increases.

In contrast, ownership is not contemplated or anticipated in the PPA terms and conditions. A specialized customer relationship does exist in its place - - specialized, as accountants have recognized, by virtue of the unique credit support, and equipment dedication, implicit in the long term contractual relationship. Stricter development standards and deadlines apply. A greater risk of default by the PPA Seller results. The greater risk of termination which accompanies any higher risk of default is exacerbated here by the absence of an opportunity to cure the completion deadline, applicable even where construction could be well underway and highly likely to be completed. Only lower levels of delay and cost risk are tolerated by PPA Buyers. Due to both the higher risk of default and the long term exposure to a different replacement product - - replacement power for up to 20 years - - higher security is demanded of PPA Sellers.

In summary, APSA Buyers experience higher risks of delay and more risk of cost increases. In return, for a more balanced set of risks, APSA Buyers are more likely to face lower risks that the Facility will not be completed. PPA Buyers tolerate lower risks of delay, and face little, if any, risk of cost increases when a Facility is successfully completed. Higher performance risk translate into a higher risk of non-completion, which, in turn, necessitates a higher level of security[23].

C. Comparison of Contractual Forms to Industry Norms:

1. A Spectrum of Forms. The purchased power industry and the turnkey and construction industry for power plants utilize a large variety of forms, with an almost infinite set of choices among possible terms and conditions. Common characteristics have, however, developed in response to market needs and pressures, such as the pressure to finance PPAs on a project finance basis or the competitive pressure toward low, fixed cost bidding in each industry.

2. Buyer's Form vs. Balanced Form. In light of the range of possible forms applicable to each industry, the IE views the subject PPA and APSA as within the bounds of industry norms in each case. However, the place of each form relative to the bounds of the industry forms is markedly different. The PPA form appears decidedly on the side which is tougher on Sellers than Buyers and significantly departs from a form which occupies a mid point among forms[24]. The PPA is appropriately characterized as a "Buyer's Form" and could reasonably constitute a starting point for negotiations. Conversely, the APSA form appears to have been

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23 Levels of security demanded in this PPA are so high that early default and termination, in certain cases, could readily lead to a windfall for the PPA Buyer.

24 See: Xcel PPA Form from its 2005 RFP. While not as balanced as the Xcel form the Company's Qualifying Facilities Power Purchase Agreement Form is closer to a well-balanced Form than the 2009 RFP PPA. Examples of this balance can be found, among others, in the Force Majeure clause (Section 13.1), lender assignment provision (Section 19), and the default provisions where cure opportunities exist (Section 11).

negotiated to completion, appears reasonably well balanced and constitutes neither a "Buyer's Form" nor a "Seller's Form".

D. Relationship of Product and Contract Differences to Unbiased Scoring:

1. Product and Contract Differences. As set forth in Comment B, above, important differences exist between power purchase agreements and asset acquisition agreements in terms of the risks allocated to buyers and sellers. The products offered - - power in one case and a power plant in the other - - are simply different. By design, power sellers internalize and price many risks otherwise absorbed by asset owners. Power purchase agreements offer a delivered product, under a fixed pricing arrangement, over a long term subject to relatively more strict development and performance standards. Asset acquisition agreements anticipate completion and extend only over the development and construction period. A more balanced sharing of risks between the future asset owner and contractor is generally revealed in the terms of asset agreements. Risks on buyers are significantly higher and risks on sellers are significantly lower in asset agreements than in power purchase agreements. Since the products are different, those differences should be, and are, reflected in the PPAs and APSAs used in the respective industries.

2. Present Scoring Deficiencies. The present APSA form is more advantageous to APSA Sellers than the present PPA form is to PPA Sellers. This unequal starting point creates a difference in the need for bidders to recommend changes to the forms in favor of the APSA resource. Due to the different position of the contract forms relative to the normative industry spectrum, it is recommended that the ten (10) point scoring factor (triggered by the request for any change in forms) be eliminated in its entirety, or alternatively, that the binary nature of the ten (10) point scoring be eliminated in favor of a scoring system that assigns no more than one (1) point to any requested modification. Even the adjusted form sought by the PPA Seller would be significantly less risky to PPA Buyers than the unadjusted APSA form is to APSA Buyers.

3. General Scoring Concerns. In accordance with Characteristics of an Effective Bidding Process, above, all costs, benefits and risks of resources should be appropriately and fairly taken into account. Taking all material factors into account, unbiased scoring would score similar resources similarly and score different resources differently. In light of the recognized differences in the allocation of risk to buyers between the two different products - - the PPA product versus and the APSA product - -, it is a concern to the IE that the present evaluation and scoring methodology does not reflect the material differences in the risks allocated to buyers under the PPAs and the APSAs. The only proposed solution the IE is aware of, the addition of an historically based premium to the bid price of rate based assets to recognize that higher level of risk, is not supported by the record or evidence here and would, in the absence of adequate factual support, smack of arbitrariness.[25] It is recommended that

25 "Getting the Best Deal for Electric Utility Customers", Electric Power Supply Association, 2004, page 15-16 (See footnote 4, NIPPC Comments, August 24, 2005). The IE is unaware of any utility or any regulatory commission which has addressed directly in its evaluation methodology in a competitive solicitation the additional

the design of any future RFP address this issue directly and quantitatively in the scoring and evaluation process.

IX. Conclusions and Recommendations

Based on our review of the RFP and related information, the conclusions and recommendations of the IE are presented in this section of the report.

1. PacifiCorp has developed a reasonably transparent process that provides the necessary information to bidders on which to base their proposal. In particular, the RFP documents clearly describe the products requested, the requirements of bidders, the evaluation and selection process, and the risk profile of the buyer. In this regard, there is sufficient information to allow bidders to assess whether or not to compete, the product of choice to bid to be most competitive, and the process by which their proposals will be evaluated.

2. The RFP represents a significant improvement over the 2003-A RFP. PacifiCorp has incorporated a number of the recommendations of Navigant Consulting, Merrimack Energy, and others. Specific steps such a including contracts for each project structure, identifying all the factors considered in the bid evaluation process and identifying how such factors will be incorporated, providing pricing forms for bidders to complete, and more clearly describing the bid evaluation and selection process leads to a more transparent process.

3. The IE has identified a number of specific issues and suggested modifications to the RFP document to ensure additional clarity and fairness to the bidders. Many of the modifications involve formatting suggestions and/or additional clarifications. For the most part, we would expect that such modifications would not materially effect the continuation and completion of the RFP process.

4. The IE believes several of the non-price criteria should be broadened to allow greater resolution to distinguish bids on a non-price basis. This includes the allocation of points or weights for both dispatchability and exceptions to the proforma agreements. The IE is of the view that the non-price criterion assigning a ten point binary weight for any exceptions to the proforma agreements needs to be modified or eliminated. In addition, PacifiCorp may want to consider using the credit matrix concept as the basis for establishing a non-price criterion for credit considerations.

5. The quantitative methodologies developed by PacifiCorp for undertaking the initial price factor evaluation (RFP Base Model) and the final short list (production cost model) are applicable for the modeling of the proposals expected in this RFP. Furthermore, the

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risk of a cost of service plant, other than by limiting a utility to the “cap” represented by its bid or its benchmark in a solicitation. Here, the operation of S.B. 26 appears to make such an approach of questionable legality.

model methodology is consistent with industry standards applied by others for conducting such a pricing analysis. While the RFP Base Model may be unique to PacifiCorp, the model methodology and concept is consistent with the approaches applied by others. Based on our initial review of the RFP Base Model, the IE has found no inconsistencies or biases in the model construct.

6. The IE will undertake a further test of the models using hypothetical bids. In this process, the IE will utilize the bid forms as contained in the RFP and create several test bids. The bids will be evaluated by PacifiCorp similar to the evaluation of actual bids. The IE will then review the results with PacifiCorp to determine if the model methodologies are consistent, fair and unbiased. It is recommended that this process be implemented soon after PacifiCorp submits its comments in this proceeding in response to the IE's report.

7. The IE has found that the methodologies and approach used by PacifiCorp for forecasting fuel and power forward prices are reasonable and consistent with industry standards. PacifiCorp uses actual market quotes and transactions as the basis for short-term prices for both power and fuel and blends into a long-term fundamental forecast for the mid to long-term. The use of actual quotes and transactions is a valid approach for capturing market prices in the short-term which is preferable to using the fundamental forecast for all years of the forecast period. Furthermore, the use of actual quotes serves to minimize or eliminate any forecasting bias in the short-term based on the timing of forecast release or the failure of the forecast to account for market volatility.

8. The IE recommends that PacifiCorp develop the forecasts for key variables associated with the evaluation of asset ownership and EPC options that the company will own and operate and provide and "lock-down" the forecasts to the IE at least two weeks in advance of receipt of bid. This would include forecasts of fixed and variable O&M costs, start-up costs, and fuel transportation costs.

9. The IE has raised several concerns with regard to the level of credit assurance required of bidders, particularly those with investment grade ratings. Also, the IE has raised several concerns over the level of credit assurance required of bidders for PPAs and asset purchase options. As noted in the discussion on contract issues in the report, the methodology used by PacifiCorp to calculate the level of credit assurance is not consistent with industry standards and is not consistent with traditional power contract damage provisions. The IE has identified several potential biases due to the level of credit assurance requirements including bias against smaller projects and a bias favoring asset purchase options relative to PPAs. The IE recommends PacifiCorp reconsider the level of credit assurance required and attempt to resolve the potential biases contained in the methodology.

10. Despite the biases contained in the level of credit assurance requirements, the IE concludes that the type of primary security required by PacifiCorp (i.e. letter of credit, guarantee or cash) and the Company's unwillingness to be subject to accounting or tax treatment that results from VIE treatment are consistent with industry standards.

11. The IE has conducted a thorough review of the two basic contract forms - - the PPA and the Asset Purchase and Sale Agreement (APSA). The IE views the subject PPA and APSA to be within the bounds of industry norms in each case. However, the place of each form relative to the bounds of industry norms is markedly different. The PPA form appears decidedly on the side which is tougher on Sellers than Buyers and significantly departs from a form which occupies a mid point among forms. The PPA can be characterized as a “Buyers Form”, while the APSA does occupy a mid point among comparable forms. The IE believes that only the potential counterparties to these contracts can propose balancing revisions with the self-interest needed to offset PacifiCorp’s interests. Even if PacifiCorp decides to make revisions to the present forms, the IE recommends that the binary weighting for exceptions to the contract as a non-price characteristic be modified or removed from the scoring in all events and that either (i) exceptions go unscored and unpenalized or (ii) points be assigned to major issues in the forms and distributed in such a way that no bidder would experience more than a one point deduction in scoring for any single issue.

12. While the present RFP is much more transparent than the previous RFP with regard to accounting and debt impacts associated with purchased power, including the identification of the methodology proposed by PacifiCorp for assessing the impacts and the opportunity for bidders to assess their accounting treatment before deciding to submit a bid, there is still a wide disparity in the positions of the parties with regard to treatment of inferred debt. Furthermore, several parties to the proceeding have raised concerns about the appropriate treatment and associated risk for PPAs in comparison to the treatment and risk for rate base plants from the perspective of both the Credit Rating Agencies and the ratepayers. Unfortunately, no party to the case has proposed an alternative methodology, supported by studies or other evidence for putting PPAs and rate base plants on an equal footing. In addition, there is no industry standard associated with either treatment of inferred debt to reflect the risk associated with a PPA or treatment of the utility’s cost of capital to reflect the risk associated with a rate base unit. The IE believes this is a major policy issue at the regulatory level that may require review and assessment by the Commission regarding the appropriate approach for assessing PPAs and rate base options. Should the Commission decide to assess this issue further in an existing proceeding or in this proceeding, we believe consideration should be given to conducting a parallel process to ensure the RFP stays on a reasonable track to ensure the resource needs for 2009 can be met.

ATTACHMENT A
PACIFICORP STANDARD FORM QF CONTRACT

Please see

http://www.pacificorp.com/File/File25896.pdf

ATTACHMENT B

MODEL DISPATCHABLE POWER PURCHASE AGREEMENT of PUBLIC SERVICE COMPANY OF COLORADO (distributed in connection with the Xcel 2005 All-Source RFP)

PROVISIONS SHOWING BALANCING OF BUYER AND SELLER INTERESTS

1. Section 11.1 Security for performance is $125/kw or approximately $66 million for a project of 525 MWs in size.

2. Section 11.2 Buyer obtains a subordinated mortgage and Seller is required to obtain from the lender its agreement to allow the PPA to remain in force even after a foreclosure on the project provided that Buyer is not in default under the PPA.

3. Section 11.2 Seller is not required to pledge its securities or membership interests to Buyer but negatively covenants to allow no one other than the Lender to hold such a pledge.

4. Section 11.2(B) Buyer agrees to cooperate and to diligently negotiate in good faith the form of the lender agreements required to enable Seller to meet the construction milestones.

5. Section 12.1 Various cure periods apply to all Seller defaults ranging from 30 to 90 days (latter comprised of two 45 day periods for finishing the project when the Commercial Operation Date is late).

6. Section 12.2 Specific lender notice and opportunity to cure provision allows lender to perform in place of Seller within required cure periods.

7. Section12.4(A) Delay Liquidated Damages for delay in Commercial Operation Date is at rate of $200/MW/day in Peak Months or $105,000/day for 525 MWs project.

8. Section 12.5 Common law is limited by provision restricting termination rights to defined defaults under agreement or other specific termination rights in agreement.

9. Section 12.6 Limitations on Net Replacment Power Costs of $125/kw and $75/kw for Delay Liquidated Damages.

10. Section 12.7 Buyer's "step in" rights to operate are acknowledged as junior to lenders.

11. Section 12.12 Duty to mitigate damages is bilateral.

12. Section 14.1 General force majeure standard allows events beyond reasonable control of the party in question. Provision recognizes government action and inability to obtain necessary permits.