Report of the Utah Independent Evaluator Regarding PacifiCorp's Draft All Source Request for Proposal 2016 Resource

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Table of Contents

Executive Summary 2

I. Introduction …………………………………………………………………….. 7

II. Background …………………………………………………………………….. 12

III. Summary of the Key Provisions of the All Source RFP …..…………………. 14

IV. Positions of the Parties ….……………………………..…………………… 26

V. Discussion of Important Competitive Bidding Issues ………………………... 30

VI. Assessment of the Contract and Related Benchmark Risk Issues ……….…… 45

VII. Conclusions and Recommendations ……………………………………….…. 55

Appendix A Role and Functions of the IE

Appendix B Red-lined Version of the RFP – Merrimack Energy's Comments

Report of the Independent Evaluator Regarding PacifiCorp's 2016 All Source 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 2016 All Source Request for Proposals (" 2016 RFP" or "2016 All Source RFP"). One of the tasks (Task A7) 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.

Utah Code Section 54-17-101, known as the Energy Resource Procurement Act requires that an affected electric utility seeking to acquire or construct a significant energy resource shall conduct a solicitation process that is approved by the Commission. The Commission shall determine whether the solicitation process complies with this Chapter and whether it is in the public interest taking into account whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electric utility located in the state.

The overall objective of the IE in this process is to ensure the solicitation process could reasonably be expected to be undertaken in a fair, consistent and unbiased manner and results in the selection of the best resource option(s) for customers in terms of price and risk. As a component of the first phase of the solicitation 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, equitable and transparent process and that the key aspects of the RFP are consistent with industry standards. To accomplish these objectives the IE has undertaken the following activities:

- Reviewed the draft RFP documents;
- Participated in bidders and stakeholders conferences prior to the development of the RFP;
- Reviewed the comments filed by all interested parties;
- Applied the "Lessons Learned" from previous RFPs, notably the 2008 All Source RFP: and
- Based on our overall industry experience in serving as IE or a related role in other power procurement processes, assessed PacifiCorp's competitive procurement approach in the 2016 All Source RFP relative to industry practices.

The IE has prepared its comments in three areas: (1) comments and recommendations on major issues identified by multiple parties and recognized by the IE as important to the fairness and transparency of the process; (2) comments on the attached contracts, with emphasis on the Power Purchase Agreement ("PPA") and the Engineering, Procurement, and Construction ("EPC") Agreement as a means of assessing the risk sharing provisions of a power purchase option versus utility ownership; and (3) comments on specific aspects of the RFP document, including suggested formatting changes and revisions/modifications designed to make the document clearer to bidders.

The 2016 All Source RFP is modeled largely on the 2008 All Source RFP that resulted in a robust response from the market and a competitive overall process. While the IE raises a number of issues in this report and also seeks clarification from PacifiCorp regarding some of the revisions made to the 2016 All Source RFP, the IE is of the opinion that the 2016 All Source RFP process should be a transparent process which is generally designed to be fair and equitable to bidders. While the 2008 All Source RFP and the 2016 All Source RFP have made strides to enhancing the comparability between utility-owned resource options (e.g. EPC, APSAs, and self-build options) and third-party firm price bids (e.g. PPAs and TSAs), we do have some concerns about the level of competition for the EPC option and the potential implications on the level of competition in the competitive procurement process. Assuming the EPC is competitively bid by a reasonable number of suppliers, the EPC option effectively takes the place of the utility benchmark resource.[1] However, if only one or two EPC bids are submitted, thus resulting in limited competition, it is not certain how PacifiCorp would make a decision to select or reject a resource or take another course of action without the presence of a benchmark.

Several parties raise major issues with regard to components of the RFP. If these issues can be resolved to the satisfaction of the parties and the Commission, it is our view that approval of the 2016 All Source RFP is a reasonable result after resolution of these issues.

Based on Merrimack Energy's review of the RFP and related information and lessons learned from the 2008 All Source RFP, the conclusions and recommendations of the IE are presented as follows:

- The 2016 All Source RFP is based largely on the 2008 All Source RFP which was approved by the Commission on September 25, 2008. Many of the provisions, procedures, evaluation criteria, evaluation protocols, evaluation and selection process, evaluation methodologies and models are either the same or very similar;

- The 2016 RFP is a reasonably transparent RFP, with a significant amount of information provided to bidders on which the bidders could base their proposals;

- Several of the lessons learned from the 2008 All Source RFP process and previous solicitations (e.g. the 2012 Base load RFP) have been applied to this RFP;

- The 2016 RFP is designed to provide the same information to all bidders;

- The products sought in this RFP are clearly defined and the information required for each type of resource alternative is specified in the RFP in a clear and concise manner. The inclusion of a wide array of eligible products and resource options should provide the opportunity for a competitive process;

[1] The EPC option would be built on an existing PacifiCorp site with infrastructure already in place. The presence of the existing asset (i.e. site and related infrastructure) may be viewed by prospective bidders as providing a competitive advantage to the EPC option.

- 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.

- Parties have raised the issue of ensuring comparability for resource evaluation, notably ensuring that utility benchmarks and third-party bids are required to compete based on the same set of rules or on a level playing field. Recent RFPs have moved in the direction of establishing a more level playing field through the application of a two stage evaluation process (i.e. indicative bid to select short list and best and final offer), price indexing options for capacity and capital related costs, contract provisions in the various contracts, and passthrough of change in law costs associated with potential environmental requirements. For the 2016 All Source RFP the Company is allowing Bidders to propose as an alternative different pricing/security structures.

- The quantitative methodologies developed by PacifiCorp for undertaking the initial price factor evaluation (RFP Base Model) and for selecting the final short list (System Optimizer and PaR models) are applicable for the modeling of the proposals expected in this RFP. Furthermore, the model methodology is consistent with and likely exceeds industry standards applied by others for conducting such a price and risk analysis. While the RFP Base Model may be unique to PacifiCorp, the model methodology and concept is consistent with the approaches applied by others. The portfolio evaluation and risk assessment methodologies are very detailed and are generally pertinent to the requirements of the Energy Procurement Resource Act.

- The evaluation and selection process is a comprehensive and creative process designed to evaluate the cost implications associated with different resource portfolios, the important non-price factors required in the Act that influence project viability, and assesses the risk parameters associated with the portfolios.

- 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.

- In the 2008 All Source RFP the IE suggested and the Commission approved eliminating the requirement to blind the bids (i.e. remove all indication with regard to the name of the bidder) before the undertaking the evaluation process. This resulted in a simpler and more efficient evaluation process. Furthermore, the IE believes that the value of blinding the bids is minimal since it is very difficult to ensure that the utility evaluation team will not know the identity of the bidders. The IE has also found that the evaluation process undertaken by PacifiCorp has not contained any undue bias toward specific bidders or types of resources.

Specific Comments on the Draft 2016 All Source RFP

- PacifiCorp has taken both positive and negative steps with regard to comparability of resources for evaluation purposes. On the positive side, PacifiCorp has included an alternative that allows bidders to provide pricing/security structures. In addition, PacifiCorp has provided additional flexibility and potential reduction in costs by providing a phase-in security posting schedule that reaches 100% of the security required by the eligible on-line date;

- PacifiCorp has proposed not offering a benchmark bid into the RFP, instead offering bidders the alternative to submit EPC bids at the existing Currant Creek site. While detailed EPC options at a Company site vetted through a solicitation process could provide a reasonable alternative to a utility benchmark, the IE is concerned about the prospect of limited competition, including only one or two EPC proposals being submitted. Another use of a benchmark resource is to establish a "cost to beat" if there is limited competition. The presence of such a benchmark can serve as a guide for PacifiCorp to decide whether to select a resource from the RFP;

- PacifiCorp has proposed to fix resources for all portfolios beyond the 2016 resource need date. The IE does not believe PacifiCorp has provided adequate justification to propose a fixed resource plan as a response to the Commission's statement in its Order in the Lake Side proceeding (Docket No. 10-035-126) that allowing future resources to float has "merit". The IE recommends that PacifiCorp provide an assessment of the pros and cons of conducting the evaluation process under the assumption of fixed versus floating future resource additions;

- PacifiCorp has revised the methodology and metric it has used in the past to calculate the price score in Step 1 of the evaluation process. The IE requests that PacifiCorp provide an explanation supporting the change in methodology and provide an example of the proposed metric for determining the price score;

- One issue that occurred in the 2008 All Source RFP process was that one bidder was eliminated because it violated the allowable 10% increase in bid price between the indicative bid and best and final offer. While all other bids met the 10% limit, the IE believes it would be clearer to bidders if PacifiCorp would clarify how the 10% limit will be calculated and applied;

- The Credit Methodology used by PacifiCorp is a sophisticated and reasonable process which continues to evolve slightly. The credit methodology and credit matrix is largely consistent with the recent approach used by PacifiCorp for assessing the security requirements of bidders. The application of the methodology has resulted in a lower level of security required in the 2016 All Source RFP relative to the 2008 All Source RFP likely due to recent decrease in gas and power prices and lower price volatility;

- The 2016 All Source RFP contains a number of revisions to the allowable delivery points in both PACE and PACW as well as clarifying the impacts of transmission line construction on the timing of project in-service dates. Given the revisions in the RFP associated with transmission issues and the importance and complexity of transmission cost impacts and access, the IE recommends that PacifiCorp offer a Transmission workshop for bidders to coincide with the Bidders Conference after issuance of the final RFP;

- PacifiCorp has proposed to limit coal options to contract terms of 1-5 years. Based on this requirement, no new coal projects or even proposals for PPAs from existing coal resources would likely participate in the RFP, potentially removing a competitive resource option. The IE recommends that PacifiCorp issue two RFPs, similar to the 2008 All Source RFP, with coal treated as an eligible option for the Utah RFP;

- PacifiCorp has proposed several changes with regard to indexing of prices. First, PacifiCorp has proposed eliminating the option that all bidders had to index a portion of their capital cost or capacity prices to selected indices. PacifiCorp cites the fact that no bid on the short list for the 2008 All Source RFP selected any price indexing options for capital or capacity-related costs. Second, PacifiCorp also proposed to eliminate indexing for both fixed and variable operations and maintenance costs. The IE recommends that PacifiCorp should be required to reinstate indexing for both capital/capacity related costs as well as fixed and variable operation and maintenance costs to allow bidders to reflect the cost structure and market risk in their pricing formulas, Even if the Commission decides to approve PacifiCorp's proposal to eliminate indexing of capital and capacity related costs, indexing for operation and maintenance costs should definitely be reinstituted consistent with industry practices to allow bidders to index such costs;

- The IE has some concerns with the proposed schedule for the 2016 All Source RFP. In particular, PacifiCorp proposes a longer period between the time of issuance of the RFP and the due date for bids. As a result, the time allotted to complete the short list evaluation and the time available for bidders to prepare a best and final offer has been reduced. The IE has proposed a slightly revised schedule designed to provide additional time for bid evaluation and preparation of the best and final offer but reduces the time available to prepare the initial bid to be consistent with the 2008 All Source RFP;

- PPA Buyers are offered more cost protection from unanticipated changes than EPC Buyers. This protection applies even for changes that result in costs which are prudently incurred by PPA Sellers. EPC Buyers in many cases would absorb the same prudently incurred increases in cost. Protection comes at a price and overall PPA charges should be expected to be higher in typical projections of life cycle costs. Whether extra costs are absorbed later by EPC Buyers in amounts that exceed the originally higher estimates of PPA charges cannot be known at present.

I. Introduction

A. Utah Law Regarding Competitive Bidding

Utah State Law 54-17-101, known as the Energy Resource Procurement Act (2005) requires that an affected electric utility seeking to acquire or construct a significant energy resource[2] shall conduct a solicitation process that is approved by the Commission. The Commission shall determine whether the solicitation process complies with this chapter and whether it is in the public interest taking into consideration whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electric utility located in the state.

Rule R746-420 outlines in detail the requirements of a solicitation process with regard to implementation of the Energy Resource Procurement Act. Among other issues, Rule R746-420 provides general provisions regarding the filing requirements for the soliciting utility in seeking approval of the solicitation, a description of the solicitation process and associated requirements, and the roles and responsibilities of an Independent Evaluator to oversee the solicitation process

The specific requirements for the solicitation process are included in Section R746-420-3 of the Rules. The key provisions by topic area in the rules are identified and briefly summarized below.

(1) ***<u>General Objectives and Requirements of the Solicitation Process</u>*** – Requires that the solicitation process must be fair, reasonable and in the public interest and be designed to lead to the acquisition of electricity at the lowest reasonable cost to retail customers in the state;

(2) ***<u>Screening Criteria – Screening in a Solicitation Process</u>*** – The utility shall develop and utilize screening and evaluation criteria, ranking factors and evaluation methodologies that are reasonably designed to ensure the solicitation process is fair, reasonable and in the public interest in consultation with the IE and Division;

(3) ***<u>Screening Criteria – Request for Qualification and Request for Proposals</u>*** – The soliciting utility may use a Request for Qualification (RFQ) process;

(4) ***<u>Disclosures – Benchmark Option</u>*** – The utility is required to identify whether the Benchmark is an owned option or a purchase option. If the benchmark is an owned option, the utility should provide a detailed description of the facility, including operating and dispatch characteristics;

(5) ***<u>Disclosures – Evaluation Methodolog</u>***y – The solicitation shall include a clear and complete description and explanation of the methodologies to be used in the evaluation and ranking of bids including all evaluation procedures, factors and weights, credit requirements, proforma contracts, and solicitation schedule;

[2] A significant energy resource is defined as a resource that consists of a total of 100 MW or more of new generating capacity that has a dependable life of ten years or more.

(6) ***Disclosures – Independent Evaluator*** – The solicitation should describe the role of the IE consistent with Section 54-17-203 including an explanation of the role, contact information and directions for potential bidders to contact the IE with questions, comments, information and suggestions;

(7) ***General Requirements*** – The solicitation must clearly describe the nature and relevant attributes of the requested resource. The solicitation should identify the amounts and types of resources requested, timing of deliveries, pricing options, acceptable delivery points, price and non-price factors and weights, credit and security requirements, transmission constraints, etc.

(8) ***Process Requirements for a Benchmark Option*** – The benchmark team and evaluation team must have no direct communications; All relevant costs and characteristics of the Benchmark option must be audited and validated by the IE prior to receiving any of the bids; All bids must be considered and evaluated against the Benchmark option on a fair and comparable basis;

(9) ***Issuance of a Solicitation*** – The utility shall issue the solicitation promptly after Commission approval;

(10) ***Evaluation of Bids*** – The IE shall have access to all information and resources utilized by the utility in conducting its analyses. The utility shall provide the IE with access to documents, data, and models utilized by the utility in its analyses; The IE shall monitor any negotiations with short listed bidders.

B. Role of the IE

Merrimack Energy Group, Inc. (Merrimack Energy) was retained by the Utah Public Service Commission (Commission) to serve as Independent Evaluator for PacifiCorp's Draft All Source Request for Proposals for 2016 Resources ("2016 All Source RFP" or "2016 RFP"). 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. The specific tasks for the Independent Evaluator under each phase of the solicitation process are listed below. The specific tasks outlined will guide the activities of the Independent Evaluator throughout the solicitation process.

1. Solicitation Process Approval

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 including bid evaluation templates, bidding documents (i.e. RFP, Bid Form or Response Package, and the proposed Contracts), disclosure of evaluation criteria (including financial and credit requirements), methods and modeling methodology to ensure the process is fair, equitable and consistent;

4. Review, analyze and validate the benchmark option cost assumptions and the proposal for disclosing information about the benchmark to potential bidders;

5. 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 (including spreadsheet screening models and production cost models). 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;

6. Provide monthly status reports to the Commission, Division, and PacifiCorp on all aspects of the solicitation approval process as it progresses;

7. Provide a written evaluation including recommendations to the Commission regarding the results of the above tasks. Include recommendations on approval of the proposed solicitation or modifications required for approval and the bases for recommendations;

8. Testify before the Commission regarding approval of the proposed solicitation, if necessary.

<u>2. Solicitation Process Bid Monitoring and Evaluation</u>

1. Monitor all aspects of the solicitation process, including: communications between bidders and PacifiCorp; evaluation and ranking of responses; selection of the "short list" of bidders; negotiations between short list bidders and PacifiCorp; ranking of the final list of alternatives; selection of energy resource(s);

2. Participate in the pre-bid conferences;

3. Following the pre-bid conference, and before the bids are due submit a status report to the Commission and the Division noting any unresolved issues that could impair the equity or appropriateness of the solicitation process;

4. Monitor communications with bidders prior to receipt of the bids;

5. Participate in the receipt of bids;

6. Establish a webpage for information exchange between bidders and PacifiCorp;

7. Monitor all communications with bidders after receipt of bids and negotiations conducted by PacifiCorp and any bidders;

8. Audit the evaluation process and validate that evaluation criteria, methods, models and other solicitation processes have been applied as approved by the Commission and consistently and appropriately applied to all bids. Audit the bid evaluations to verify that assumptions, inputs, outputs and results are appropriate and reasonable;

9. Advise the Commission, Division and PacifiCorp of any issue that might reasonably be construed to affect the integrity of the solicitation process and provide PacifiCorp an opportunity to remedy the defect identified;

10. Periodically submit written status reports to the Commission and Division on the solicitation;

11. File a report with the Commission and Division detailing the methods and results of PacifiCorp's initial screening evaluation of all bids. Include a description of the bids, selection criteria, and provide the basis for the selection of the short-listed bids and rationale for eliminating bids.

3. Participation in the Energy Resource Decision Approval Process

1. File a detailed final report (confidential and public versions) with the Commission and provide a copy to the Division within 21 days of PacifiCorp's final ranking of bids and identification of its Energy Resource Decision;

2. Participate in any Utah technical conferences related to the Energy Resource Decision Approval Process;

3. Testify during the Energy Resource Decision Approval Process in Utah.

In addition to the Introduction, the report is presented in six other sections. Section II provides a brief background on PacifiCorp's Draft 2016 All Source RFP process to date. Section III describes the key provisions of the 2016 All Source RFP and compares the key provisions to the 2008 All Source RFP since the structure of the 2016 All Source RFP and solicitation process are largely modeled after the 2008 All Source RFP. This Section also provides a listing of the "Lessons Learned" from the 2008 RFP that should be applicable to the design of the 2016 All Source RFP. Section IV provides a summary of the positions on the parties in the case as presented in the comments filed by each party. Section V provides a detailed discussion of major/important competitive bidding issues and suggestions/recommendations for addressing the major RFP issues associated with the Draft 2016 All Source RFP. Section VI provides a review and assessment of major contract issues, particularly the differences in contract risk considerations between a Power Purchase Agreement (PPA) and an Engineering, Procurement and Construction (EPC) contract. Finally, Section VII provides our conclusions and recommendations.

II. Background

On October 5, 2011, PacifiCorp filed an application with the Utah Public Service Commission ("Commission") requesting approval of a solicitation process to acquire an all source resource for the 2016 time period ("2016 All Source RFP"). A Scheduling Conference on the approval of the solicitation process was held on October 13, 2011, with a Scheduling Order issued by the Commission on October 19, 2011. In addition, the Company held a public meeting on September 1, 2011 in anticipation of release of the draft proposed RFP as well as a Bidders Conference on October 20, 2011 to review the key parameters of the Draft RFP.

Based on the Schedule in this Docket (Docket No. 11-035-73), comments on the draft RFP were due on November 18, 2011 and the Report of the Independent Evaluator on the draft RFP is due on November 28, 2011.

PacifiCorp's current RFP is based largely on the previous 2008 All Source RFP ("Solicitation Process for a Flexible Resource for the 2012-2017 Time Period – Docket Nos. 07-035-94 and 10-035-126) which resulted in the selection and approval of the acquisition of a 637 MW natural gas-fired combined cycle generating plant located adjacent to PacifiCorp's existing Lake Side Generating Unit in Vineyard, Utah County, Utah ("Lake Side 2"). Under the 2016 All Source RFP the Company is seeking up to 600 MW of system resources as of June 1, 2016.

The scope of the draft 2016 All Source RFP is focused on system-wide, east and west control area, energy and capacity generation which is capable of delivering energy and capacity in or to the Company's Network Transmission system. Bidders could submit proposals for any one of seven products or resource alternatives listed in the RFP plus three eligible resource exceptions (Qualifying Facility, eligible renewable resources or load curtailment) in three separate bid categories (i.e. Base Load, Intermediate Load and Summer Peak – Q3 Purchases). The resource alternatives include power purchase and tolling services agreements, Engineering, Procurement and Construction ("EPC") option at a defined PacifiCorp site as well as asset purchase and sale agreements on a bidders' site. Minimum bid size (except for resources that qualify for an exception) is 100 MW with a minimum term of 5 years.

The initial draft of the 2016 All Source RFP was provided to the IE and posted on PacifiCorp's website on or around October 13, 2011.[3] The draft RFP provided a detailed description of the resource alternatives sought by PacifiCorp, the logistics for submitting a bid including the information, forms, and schedules 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. The draft RFP contains seven Appendices and twenty Attachments, including applicable contractual agreements. In addition, there are Forms in the document for bidders to fill out and submit with their proposal. Finally, the draft RFP contains a description of the role of the Independent Evaluator in the bidding process, although a Code of Conduct included with the 2008 All Source RFP is not included in the 2016 All Source RFP. The Draft RFP was modeled on the basis of the 2008 All Source RFP, with several revisions to reflect lessons learned in the 2008 RFP process.

[3] PacifiCorp provided the IE with a red-lined copy of the 2008 All Source RFP with the changes from the 2008 All Source RFP that are proposed for the 2016 All Source RFP along with a clean version of the 2016 All Source RFP.

While many of the same provisions and parameters of the RFP and contracts remain the same or similar from the previous 2008 All Source RFP there are a few “major” changes initiated in this 2016 All Source RFP, including:

1. PacifiCorp opted to not include a Benchmark resource in this RFP;

2. Instead of soliciting for bids over a multiple year period as PacifiCorp has done in the past, this RFP is focused on a single year, soliciting bids for a 600 MW resource to be available in 2016;

3. PacifiCorp removed the option for indexing a portion of the capital cost or capacity price for bidders and also removed the indexing option for fixed and variable O&M costs.

The 2016 All Source RFP is another RFP among a series of RFPs for conventional supply-side resources developed and implemented by PacifiCorp over the past six to seven years.

III. Summary of the Key Provisions of the All Source RFP

This Chapter of the Report will provide a high level description of the Draft All Source Request for Proposals 2016 Resources ("2016 All Source RFP"), including a comparison between the requirements of the 2016 RFP and the 2008 All Source RFP, PacifiCorp's previous RFP. In addition, the "Lessons Learned" from our perspective as Independent Evaluator for the 2008 RFP are described in this Section of the Report.

A. RFP Background and Lessons Learned From Previous RFPs

PacifiCorp's Draft 2016 All Source RFP is largely based on the 2008 All Source RFP with some revisions. Since many of the parameters of the 2016 All Source RFP are similar to the 2008 All Source RFP, many of the conclusions and recommendations addressed in the IE report are consistent and appropriate for assessing this solicitation as well. Merrimack Energy's Final Report of the Utah IE for PacifiCorp's 2008 All Source Request for Proposals reached the following conclusions and recommendations:

- The RFP process is a highly transparent process, providing detailed information about the requirements for bidding, the products requested, the evaluation methods and methodology, the evaluation process, bid evaluation criteria (both price and non-price), the weights for the criteria, information required of the bidder, and the requirements of the bidder for submitting a proposal;

- The 2008 RFP resulted in a robust response from the market for base load and intermediate resources as requested. This resulted in a very competitive process;

- With regard to the 2008 All Source RFP, the solicitation process and procedures developed and implemented by PacifiCorp, including the bid evaluation and final selection process and methodologies are, in substance, consistent with Utah competitive procurement requirements and industry practices and led to a fair, consistent and unbiased evaluation and selection process;

- Lessons learned from previous PacifiCorp solicitation processes have had an impact in designing and implementing recent procurement processes such as the 2008 All Source RFP. The IE found that several of the issues raised by the Bidders and the IEs in previous RFPs (i.e. credit issues, timing of contract negotiations, comparability issues, etc.) were not issues in the 2008 All Source RFP due to revisions in the RFP to address these issues;

- The RFP allowed bidders the opportunity to offer proposals for a range of products, options, and alternatives;

- PacifiCorp offered bidders a range of resource alternatives which allowed bidders to structure their proposals to take maximum advantage of their capabilities and project characteristics. The definition of the products and the information required from bidders for each alternative were clearly defined in the RFP;

- The combination of the range of resource alternatives and the allowance for bidders to offer alternative bids led to creative project offerings;

- The two-stage bidding process – indicative bid to select a short list and best and final offer from short listed bidders – proved to be a very effective process. This process allowed bidders on the short list to conduct further analysis of the cost of their projects and update pricing closer to the time of initiating contract negotiations. The pricing submitted by Bidders at the best and final stage was generally well developed and the costs were generally known with confidence;

- The bid evaluation models and methodologies were generally appropriate for the cost and risk analysis undertaken by PacifiCorp;

- The 2008 All Source RFP took several important steps in the right direction in moving toward comparability for third-party power purchase or tolling service agreements and cost of service options. This included the allowance for indexing of capacity or capital costs, contract provisions designed to balance risk, the implementation of the two-stage pricing process (initial bid/best and final offer) and the recognition that contract negotiations would address both price and non-price factors;

- RFP documents were generally transparent, comprehensive and effective in describing the overall competitive bidding process and the requirements of bidders;

- Bidders and other interested parties had the opportunity to comment on the RFP, contracts and related documents. PacifiCorp made changes to the documents based on comments filed by the interested parties and the IEs prior to issuance of the final RFP;

- All bidders were treated the same and provided access to the same information, including both third-party bidders and the benchmark team. The PacifiCorp management team was very effective in providing consistent information to all bidders even during individual conference calls with bidders;

- The Bid Pricing Input Sheets (Form 1) were clear and transparent and led to consistent information provided by all bidders. PacifiCorp's efforts also to offer a workshop with bidders to review and explain the Pricing Input Sheets was a positive step for ensuring that bidders fully understood the information they were asked to provide;

- PacifiCorp's revision in the 2008 All Source RFP to only require Bidders to submit a commitment letter 20 days after notification of their inclusion on the Final Short List did not cause any concerns or complaints from Bidders in contrast to the issues raised by Bidders in a previous RFP to the posting requirement for Bidders to provide a commitment letter early in the bidding process;

- PacifiCorp offered their own sites to Bidders which provided several options for bidders to consider in structuring their proposals;

- The Bid evaluation models and methodologies are generally applicable for the cost and risk analysis undertaken by PacifiCorp. In particular, the models and methodology underlying the Step 1, Step 2 and Step 3 analyses are state of the art and provide very comprehensive and complete evaluation results;

- The price evaluation methodology effectively addressed overall cost, uncertainty, and risk. The risk assessment process, which evaluated multiple risks with stochastic and scenario analysis including gas and electricity prices, CO2 emission costs, and the impacts of hydro generation, load and thermal outages led to the selection of a robust set of portfolios;

- The IE raised several concerns with regards to the due diligence process for acquisition of an existing generation resource. PacifiCorp has included an Attachment to the 2016 All Source RFP that identifies due diligence issues. However, the IE suggests that PacifiCorp brief the IE on a more regular basis on the due diligence process and provide analysis of due diligence issues as they are completed rather than waiting until the IE requests copies of the due diligence memorandum;

- The Term Sheet process is an excellent step to ensure that the Company and the Bidder are in full agreement on the elements of the bidders' proposal;

- All bids were evaluated using the same input assumptions and evaluation methodology. In addition, the IRP and RFP were closely linked, with generally the same assumptions and modeling methodologies used for both processes;

- The blinding of the questions and answers from bidders through the IE website prior to bid submission was effective in encouraging bidders to ask questions without identifying their affiliation;

- The IRP group and quantitative analysis groups within PacifiCorp were thorough and responsive in completing the Step 2 and Step 3 analyses over a very short timeframe. The members of this group were always able to provide thorough responses and explanations of the results and basis for the analysis;

- The RFP took several important steps in the right direction in moving toward comparability for third-party power purchase agreements and cost of service options;

- PacifiCorp made significant strides in developing a credit methodology, credit support amounts and a security posting schedule that leads to credit requirements that are consistent with industry standards and offer some flexibility to bidders;

- PacifiCorp's decision to address imputed debt impacts at the final bid selection phase of the process rather than in the initial evaluation phase is a positive step for encouraging third-party bidder participation;

- The information provided for the Benchmark resource options was totally consistent with the information required of third-party bids. This led to a reasonably consistent evaluation based on the same level of information provided by all bidders;

- Consistent with the 2008 solicitation process, most bidders were not proactively involved in the RFP development process and did not submit comments on the process or documents. For the process to be effective and to reflect market requirements, we encourage more involvement from bidders or industry associations to identify issues with the documents and process in advance of issuance of the final RFP.

B. Comparison of the Key Provisions From the 2016 All Source RFP and the 2008 All Source RFP

For purposes of providing a comparison between the key provisions of each RFP, Exhibit 1 lists the key provisions in both the 2016 Draft All Source RFP and the Final 2008 All Source RFP, highlighting the differences between the two documents by category.

Exhibit 1
Comparison of the 2016 All Source and 2008 All Source Draft RFPs

RFP Characteristics	All Source RFP	2008 RFP
Resource Requirements	PacifiCorp is seeking approximately 600 MW of cost-effective resources to meet the Company's System Position beginning in June 2016.	PacifiCorp was seeking up to 1,500 MW of cost effective resources to meet system needs during the 2014-2016 timeframe
Resource Timing – On-line Date	PacifiCorp is seeking unit contingent or firm capacity and associated energy resources to be available for dispatch or scheduling by June 1, 2016.	PacifiCorp requested unit contingent or firm resource capacity and associated energy available for dispatch or scheduling by June 1, 2014, June 1, 2015, and/or June 1, 2016.
Eligibility	This RFP is seeking capacity and energy for Base Load, Intermediate Load and Summer Peak (Q3) resources to meet the Company's system position beginning in June 2016. Unless exceptions apply, a Bidder's proposal must exceed or equal 100 MW and have a fixed term of at least 5 years. Resource bids must provide unit contingent or firm	The 2008 All Source RFP sought seeking capacity and energy for Base Load, Intermediate Load and Summer Peak (Q3) purchases. All bids from new or existing coal resources will be considered by the Company, and, during the evaluation process, will be given appropriate weight based on CO2 risks. In addition, unless

	capacity and associated energy incremental to the Company's existing capacity and further be available for dispatch or scheduling by the Eligible Online Date. Bids from new or existing coal resources shall be limited to a Maximum Term of less than five years.	a resource qualifies for one of the exceptions, the minimum bid is for 100 MW or greater and a minimum term of 5 years. Resource bids must provide unit contingent or firm capacity and associated energy incremental to the Company's existing capacity and further be available for dispatch or scheduling by the Eligible Online Date.
Bid Categories	Bid categories include Base Load (i.e. > or = to 60% capacity factor); Intermediate Load (i.e. capacity factor of 20-60%); and Summer Peak Q3 purchase (i.e. July – September HE 07 through HE 22 PPT)	Bid categories included Base Load (i.e. > of equal to 60% capacity factor); Intermediate Load (i.e. capacity factor of 20-60%); and Summer Peak Q3 purchase (i.e. July – September HE 0700 through HE 2300 PPT)
Resource Alternatives	Resource Alternatives include: (1) Power Purchase Agreement (may include geothermal or biomass); (2) Tolling Service Agreement; (3) EPC (PacifiCorp site and specifications); (4) Asset Purchase and Sale Agreement (Bidder site); (5) Purchase of an Existing Facility; (6) Purchase of a Portion of a facility jointly owned or operated by the Company; (7) Restructuring of an Existing PPA or Exchange Agreement or (8) Exceptions which include (a) Load Curtailment or (b) QF or (c) Eligible Renewable Resource (Company must be able to dispatch or schedule renewable resource). PPAs and TSAs are not eligible to bid on the	Resource Alternatives included: (1) Power Purchase Agreement (may include geothermal or biomass); (2) Tolling Service Agreement; (3) Asset Purchase and Sale Agreement (PacifiCorp site and specifications – Currant Creek or Lake Side site); (4) Asset Purchase and Sale Agreement (Bidder site); (5) Purchase of an Existing Facility; (6) Purchase of a Portion of a facility jointly owned or operated by the Company; (7) Restructuring of an Existing PPA or Exchange Agreement or (8) Exceptions which include (a) Load Curtailment (b) QF; or (c) eligible renewable resource. PPAs and TSAs could also be bid on one of PacifiCorp's

	PacifiCorp identified site.	identified sites. PacifiCorp indicated based on comments that it will allow bids from geothermal and biomass resources with a capacity of 10 MW or greater. These options are included as third "exception".
Bid Alternatives	Bidders are allowed to submit a base proposal and up to 2 alternatives for the same bid fee. Bidders will also be allowed to offer additional alternatives as follows: (i) the fourth through sixth additional alternatives at a fee of $1,000 each; (ii) the seventh additional alternative at a fee of $2,000 and (iii) the eighth additional alternative at a fee of $3,000. Alternatives will be limited to different bid capacities, contract terms, cooling technologies, in-service dates, and/or pricing/security structures.	Bidders were allowed to submit a base proposal and up to 2 alternatives for the same bid fee. Bidders will also be allowed to offer additional alternatives as follows: (i) the fourth through sixth additional alternatives at a fee of $1,000 each; (ii) the seventh additional alternative at a fee of $2,000 and (iii) the eighth additional alternative at a fee of $3,000. Alternatives will be limited to different bid capacities, contract terms, cooling technologies, in-service dates, and/or pricing structures.
Bidding Process	The Company will conduct a multi-stage process. In the first stage, the bidder must submit the "Intent to Bid Form". The Intent to Bid Form includes responses to the information requested in Appendices A and B. In the second stage, bidders are required to submit their proposals and respond to the requirements for the type of resource alternative they are proposing. All bidders must submit the Form 1 Pricing Input Sheets. Bid that make the short list will be allowed to provide a Best and Final Offer. Best and Final Prices must be within 10% of the Bidders	The Company conducted a multi-stage process. In the first stage, the bidder must submit the "Intent to Bid Form". The Intent to Bid Form includes responses to the information requested in Appendices A and B. In the second stage, bidders are required to submit their proposals and respond to the requirements for the type of resource alternative they are proposing. All bidders must submit the Form 1 Pricing Input Sheets. Bid that make the short list will be allowed to provide a Best and Final Offer. Best and Final Prices

	original bid selected in the initial short list.	must be within 10% of the Bidders original bid selected in the initial short list.
Utility Bid Options	The Company proposes to not submit a benchmark resource proposal for any category.	In this RFP, PacifiCorp proposed a Benchmark Resource in the Base Load Bid Category. The Company's generation group will submit the Company's Self-Build option subject to the same requirements as a third-party bidder.
Evaluation Process – Short List Selection	PacifiCorp proposes a two-stage price evaluation process, with multiple steps as will be described in more detail below. The two-stage evaluation process is the same as used in the 2008 RFP. The two stages include (1) an Indicative Bid stage as the basis for selecting a short list and (2) Best and Final Offer. In the first step to select a short list, the Company intends to evaluate each bid received in a consistent manner by separately evaluating the non-price characteristics of the resource and the price characteristics. Price will account for 70% of the score and non-price for 30%. From a pricing perspective, all bids will be evaluated using the RFP Base Model. Bids with a price less than or equal to 60% of the adjusted price projection will receive all the points (70%); Bids with a price greater than 140% of the adjusted price projection will receive 0%; Bids with a price greater than 60% but less than 140% of the adjusted price will	PacifiCorp utilized a multi-stage price evaluation process. The original proposal was for exactly the same pricing metric as in the previous RFP. However, based on comments from the Division, PacifiCorp decided to offer a revised metric. In the first stage to select a short list bids will be evaluated based on price (weighted at 70%) and non-price (weighted at 30%), all bids will be evaluated using the RFP Base Model. Bids with a price less than or equal to 60% of the adjusted price projection will receive all the points (70%); Bids with a price greater than 140% of the adjusted price projection will receive 0%; Bids with a price greater than 60% but less than 140% of the adjusted price will be awarded percentages based on linear interpolation. Pursuant to Merrimack Energy's recommendations, PacifiCorp may revise the market ratio range and allocation of price points based on the costs of the actual bids to maintain the

	be awarded percentages based on linear interpolation. PacifiCorp may revise the market ratio range and allocation of price points based on the costs of the actual bids to maintain the price/non-price split. Bid that make the short list will be allowed to provide a Best and Final Offer. Best and Final Prices must be within 10% of the Bidders original bid selected in the initial short list.	price/non-price split. Bid that make the short list will be allowed to provide a Best and Final Offer. Best and Final Prices must be within 10% of the Bidders original bid selected in the initial short list.
Non-Price Evaluation	In Step 1 of the evaluation process, price and non-price weights are combined to select the short list within each resource Category. The non-price characteristics include the same criteria as the previous RFP: Development Feasibility/Risk, Site Control and Permitting, and Operational Viability/Risk Impacts	In Step 1 of the evaluation process, price and non-price weights were combined to select the short list within each resource Category. The non-price characteristics include Development Feasibility/Risk, Site Control and Permitting, and Operational Viability/Risk Impacts
Detailed Evaluation	PacifiCorp intends to subject the short listed bidders to a detailed price/risk evaluation in three remaining steps. In Step 2 PacifiCorp will use the Ventyx Energy System Optimizer model to develop optimized portfolios under various assumptions for future emission levels and market prices. In Step 3a, PacifiCorp will use the PaR model in stochastic mode to develop expected PVRR and risk measures for the optimal portfolios developed from Step 2. In Step 3b, PacifiCorp will	PacifiCorp subjected the short listed bidders to a detailed price/risk evaluation in three remaining steps. In Step 2 PacifiCorp will use the CEM model to develop optimized portfolios under various assumptions for future emission levels and market prices. In Step 3a, PacifiCorp will use the PaR model in stochastic mode to develop expected PVRR and tail risk PVRR measures for the optimal portfolios developed from Step 2. In Step 3b, PacifiCorp will subject the

	subject the optimal portfolios to a more in-depth deterministic dispatch model using the System Optimizer, with each portfolio being assessed for each of the future scenarios described in Step 2 above.	optimal portfolios to a more in-depth deterministic dispatch model using CEM with each portfolio being assessed for each of the future scenarios described in Step 2 above.
Price Indexing Mechanism	PacifiCorp proposes to eliminate the option for bidders to index a portion of their capacity price or capital cost.	Bidders were allowed to index their capacity price and capital cost to variable indices. Bidders must provide a minimum of 60% of the capacity charge or capital cost as fixed and may index 40%. A maximum of up to 25% may be indexed to the Consumer Price Index and 15% to the PPI – Metals and Metal Products. The bidders will be allowed to index from the time of bid submission or contract execution until the earlier of the time the Bidder executes the EPC Agreement or the Bidder achieves project financing.
Credit Requirements	PacifiCorp provides Attachment 14: Credit Methodology. The credit methodology is based on the Base Load Bid category. Credit requirements for the other two categories will be determined based on a percentage of the amount contained in the credit matrix. Credit requirements are distinguished by asset backed and non-asset backed agreements. In addition, security amounts are established by credit rating and bid size. The schedule for posting credit for the selected project is listed in Attachment	PacifiCorp provides Attachment 21: Credit Methodology. The credit methodology is based on the Base Load Bid category. Credit requirements for the other two categories will be determined based on a percentage of the amount contained in the credit matrix. Credit requirements are distinguished by asset backed and non-asset backed agreements. In addition, security amounts are established by credit rating and bid size. The schedule for posting credit for the selected project is listed in the

	14, with 100% of the security required to be posted at the Effective Date + 38 months or the Eligible online date. The Company will require each bidder to satisfy the specific qualification, credit and capability requirements 20 business days after the Bidder is notified by the Company that the bidder has been selected for the final short list..	Attachment with 100% of the security required 24 months after the effective date of the contract. The Company will require each bidder to satisfy the specific qualification, credit and capability requirements 20 business days after the Bidder is notified by the Company that the bidder has been selected for the final short list.
Transmission	The Company is interested in resources that are capable of delivery into or in the Company's network transmission system in PACE or PACW. Specific delivery points of primary interest to PacifiCorp are identified. Bidders will bear 100% of the costs to interconnect to PacifiCorp's transmission system. Bidders are responsible for any costs on third party transmission systems necessary to deliver the power to the PacifiCorp system. Attachment 20 is included which provides proxy costs to integrate resources into the system. PacifiCorp has added delivery points to reflect the request for delivery of power into the western part of the Company's system.	The Company is interested in resources that are capable of delivery into or in the Company's network transmission system in PACE or PACW. Specific delivery points of primary interest to PacifiCorp are identified. Bidders will bear 100% of the costs to interconnect to PacifiCorp's transmission system. Bidders are responsible for any costs on third party transmission systems necessary to deliver the power to the PacifiCorp system. Attachment 13 is included which provides proxy costs to integrate resources into the system. PacifiCorp has added delivery points to reflect the request for delivery of power into the western part of the Company's system.
Accounting Issues	With respect to Variable Interest Entity treatment, the Company is unwilling to be subject to accounting or tax treatment that results from VIE treatment.	With respect to Variable Interest Entity treatment, the Company is unwilling to be subject to accounting or tax treatment that results from VIE treatment.

	To the extent that PacifiCorp rejects a proposal submitted in this RFP because it triggers VIE treatment, PacifiCorp shall provide documentation to the IEs justifying the basis for the decision.	To the extent that PacifiCorp rejects a proposal submitted in this RFP because it triggers VIE treatment, PacifiCorp shall provide documentation to the IEs justifying the basis for the decision.
Imputed Debt	PacifiCorp will not take into account potential costs to the Company associated with direct or inferred debt as part of the economic analysis in the initial or final shortlist evaluation. The Company may take imputed debt costs into account when seeking acknowledgement or cost recovery for the resource selected. The Company will bear the burden to demonstrate to the satisfaction of its regulators the validity, magnitude and impacts of any such projected costs. At the request of each Commission (Utah and Oregon) PacifiCorp will be required to obtain a written advisory opinion from a rating agency to substantiate the utility's analysis and final decision regarding direct or inferred debt.	PacifiCorp will not take into account potential costs to the Company associated with direct or inferred debt as part of the economic analysis in the initial or final shortlist evaluation. The Company may take imputed debt costs into account when seeking acknowledgement or cost recovery for the resource selected. The Company will bear the burden to demonstrate to the satisfaction of its regulators the validity, magnitude and impacts of any such projected costs. At the request of each Commission (Utah and Oregon) PacifiCorp will be required to obtain a written advisory opinion from a rating agency to substantiate the utility's analysis and final decision regarding direct or inferred debt.
Code of Conduct	A Code of Conduct is not included in the RFP, presumably since PacifiCorp is not offering a Benchmark resource.	A Code of Conduct was included as Attachment 20 to the RFP.
Benchmark Bids	PacifiCorp does not propose to submit a benchmark bid.	The Company originally proposed to submit self-build proposals into the RFP rather than Benchmarks. However, based on comments, the Company decided to submit benchmarks.
Role of the IE	Attachment 18 to the RFP	Attachment 4 to the RFP

	describes the role of the IE in the process.	described the role of the IE in the process.
Contracts	The Company provides a sample PPA, TSA, APSA, and EPC Agreements.	The Company provided a sample PPA, TSA, and APSA agreement
Information Required of Bidders	The RFP contains a matrix that identifies the information requirements for each resource alternative.	The RFP contained a matrix that identifies the information requirements for each resource alternative.
Schedule	A detailed expedited schedule is provided in the RFP	A detailed expedited schedule was provided in the RFP

IV. Positions of the Parties

As noted, interested parties were allowed to submit comments by November 18, 2011 on the application for approval of the RFP, including the Draft RFP and associated documents. Comments on the draft RFP were filed on the due date by the Division of Public Utilities, Utah Association of Energy Users (UAE), 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 ("Division") recommends that the Public Service Commission reject the Application of Rocky Mountain Power for Approval of a Solicitation Process, Docket No. 11-035-73. The Division makes a number of recommendations designed to improve the solicitation process and requests that the Commission invite the Company to make the necessary changes and to resubmit its Application to the Commission for approval.

The Division of Public Utilities focused its comments on several areas associated with the draft RFP: These include (1) Lack of a Benchmark; (2) Price Indexing; (3) Bid Evaluation Process: (4) Fixed Post-2016 Resources; (5) Clarification of Deferral/Acceleration; (6) Coal Resources; (7) Bidder Litigation; (8) Typographical Edits; The positions and recommendations of the Division with regard to each of the above issues are summarized below.

Lack of a Benchmark

The Division is concerned that the Company is not proposing to submit a benchmark bid, unlike other recent RFP dockets. The Division believes that a benchmark bid by the Company, vetted by the Independent Evaluator, gives additional assurance to Utah regulators and interested parties that an RFP process results in the lowest-cost least-risk resource.

The Division recommends the Company should be required to prepare a benchmark bid.

Price Indexing for Bids

The Division states that the Company should include the option to allow for limited inflationary adjustments in order to not potentially discourage some bidders. Although no bidder from the previous RFP that made the short list proposed price indexing in their bid, there may be bidders who want to use some form of indexing option for this RFP. The Division also notes that in the previous RFP docket the Commission supported the use of an indexing option.

The Division recommends the Company be required to reinstitute language in the 2016 RFP allowing for some inflationary or cost-adjustment factors such as was included in prior RFPs.

Bid Evaluation Process

The Division is concerned that the Company's 2016 RFP bid evaluation process appears to be overly simplistic since the Company is taking the latest IRP Preferred Portfolio and creating a "hole" for 2016, leaving everything else in the Preferred Portfolio fixed. Given that the Company is making available to bidders its site for another gas plant at its Currant Creek site (i.e. Currant Creek II), the 2016 RFP appears to be heavily weighted in favor of EPC bidders at that site. Given the structure of the RFP, especially the bid evaluation methodology, the Division is concerned that non-Currant Creek II bidders will be disadvantaged, making it difficult to determine if a winning bid from the 2016 RFP can confidently lead to the lowest-cost, least-risk resource.

The Division recommends that the Company should demonstrate that its "All Source" RFP does not, in reality, heavily advantage Currant Creek EPC bidders. Or alternatively, that the Company amend its 2016 RFP to be an RFP solely at its brown field Currant Creek site.

Fixed Post-2016 Resources

The Division notes that except for Front Office Transactions, the company is proposing to fix post-2016 IRP resources as part of its bid evaluation methodology. The Division maintains, as it did in the Lake Side 2 proceeding (Docket No. 10-035-126), that fixing IRP resources in the outer years of the study does not allow bidder proposals to potentially defer those IRP resources and, thus, may understate the total potential present value of the proposal. The Division further notes that the Commission recognized in its Order in Docket No. 10-035-126, that the Division's recommendation to not fix any future IRP resources in evaluating the bids in future RFPs "had merit" and would have avoided some of the trouble that arose in the Lake Side 2 approval docket. The Division cites the testimony of Mr. Richard Hahn from Docket No. 10-035-126. The Division believes that the same problems in evaluation methodology that were identified by the Division's consultant (Mr. Hahn) in the Lake Side 2 approval docket exist in the current 2016 RFP proposal. The Division believes especially that the fixing of future resources remains problematic in the 2016 RFP. The Division also believes the Company should re-examine its assumptions regarding unmet energy.

The Division recommends that fixing post-2016 resources is a significant issue that the Commission should resolve in this Docket. The Division recommends that the Company not fix post-2016 resources in its bid evaluations.

Clarification of Deferral/Acceleration

The Division requests that PacifiCorp should clarify what it means in its discussions of deferral and acceleration in lieu of the statements of the Company in response to DPU data request 1.5 and the discussion contained under the Flexibility of Proposals section in the RFP.

Coal Resources

The Division states that the Company's statement about the eligibility of coal resources may be contradictory and lacks specificity. The Division states that the Company needs to be more specific about the circumstances under which a coal resource could be genuinely considered in the 2016 RFP. If the Company would accept a coal-based proposal under an exception, then it needs to clearly include this fact in the exceptions sections. If the Company really will not consider a coal resource under any circumstance, it should state that clearly as well. Again, the Company, bidders, Independent Evaluator, and regulators should not spend their time and effort with bids that the Company essentially will not consider.

The Division, therefore, recommends that the Company should clarify the circumstances (if any) under which a coal resource would be seriously considered.

Bidder Litigation

The Company indicates that it will not accept bids from entities that are in, or threatening "material" litigation against the Company. The only specific criterion for "materiality" mentioned by the Company is that the dollar amount at issue is "in excess of $5 million. The Division questions the propriety of allowing into the bidding any entity that is in, or threatening, litigation against PacifiCorp. In any case, the Division is of the opinion that $5 million is too high a threshold for materiality. At a minimum, the Company should clarify the circumstances under which it would negotiate with a bidder that was suing it, and why that should create no potential appearance of impropriety.

Utah Association of Energy Users

The Utah Association of Energy Users (UAE) submitted preliminary comments on November 18, 2011. UAE states that it hopes to see a meaningful evaluation by the IE of the following issues:

1. The likely impacts of any changes made to this RFP from the prior RFP;
2. How well this RFP responds to the IE's suggestions from the prior RFP;
3. How well this RFP achieves comparability with respect to the evaluation of different types of resources;
4. Whether the credit requirements are appropriate, fair and not unduly restrictive or punitive; and
5. Whether the appendices and attachments, including pro forma contracts, are fair and reasonable.

UAE has identified one concern based on a preliminary review of the draft RFP. That is, the RFP limits coal resources to contracts with terms of 1-5 years, based on the requirements of other states. This restriction will likely ensure that coal resources have no possibility of meaningful participation in this RFP. State laws and policies that impose additional costs on the PacifiCorp system should be assigned directly to the responsible states. Unless coal facilities are permitted to bid and participate in the RFP process under fair and comparable terms as any other resource, the system may be deprived of the lowest cost resources and there may be no practical means of determining whether and to what extent the laws and policies of other states have imposed greater costs on the system. UAE submits that coal resources should be permitted to bid into the RFP without restriction.

Office of Consumer Services

The Office of Consumer Services comments address two specific issues:

- The Company's decision to not include a benchmark resource;
- The bid evaluation process utilizing the Company's preferred portfolio from the 2011 Integrated Resource Plan (IRP).

Lack of a Benchmark Resource

The Office of Consumer Services raises issues about the lack of a benchmark resource. The Office of Consumer Services states the Office typically prefers that the Company include a benchmark resource as part of the solicitation since the presence of a benchmark can bring value to the process. The Office, however, is sympathetic to the Company's experience with a benchmark in the last RFP, including the cost and time incurred to develop the benchmark. In that instance a competing bid was offered at similar costs to the Company's benchmark but the competing bid provided advantages in other areas and thus was selected as the resource to acquire. However, the Office also notes that one of the purposes of the benchmark is to be used in the evaluation of other RFP bids. If the Commission allows the Company to go forward without a benchmark, it is even more important to ensure that the evaluation process is not biased or otherwise flawed.

Bid Evaluation

The Office is concerned that using the Company's proposed preferred portfolio from its 2011 IRP will result in a biased analysis. The Office notes that the methods used to derive the Company's preferred portfolio contained several fundamental flaws. Of particular concern is the extent to which the Company's preferred portfolio resulted from hand selected resources and hard-wired restrictions, rather than being selected for its superior performance in robust scenario evaluations where risk, cost and reliability were balanced. To the extent that the preferred portfolio is not reflective of an optimal portfolio, it also cannot be relied upon to select the best result from the RFP process. The analysis must be based upon a preferred portfolio that has been thoroughly vetted and is specifically found to be in the public interest.

The Office is concerned not only that the Company intends to use its flawed IRP in the evaluation of bid resources but also that the evaluation methodology itself will potentially create further bias in the evaluation process. Using the methodology proposed by the Company by simply removing a specific plant from the preferred portfolio prevents examination of whether a resource with fundamentally different characteristics may perform better and provide a more cost-effective and lower risk option to meet customer electric demands.

The Office recommends that the Commission require the evaluation of offered resources in the 2016 RFP be based on the outcome of a robust IRP analysis and not the Company determined preferred portfolio. The Office also recommends that the evaluation methodology be changed such that it doesn't bias resources with different characteristics.

V. Discussion of Important Competitive Bidding Issues

This section begins with a listing of the factors that are important for an effective competitive bidding process in any state and under any circumstance based on Merrimack Energy's experience and consistent with Utah statutes and Commission directives. Following these factors, this section continues with a more detailed assessment and discussion of the important competitive bidding issues associated with the 2016 All Source RFP. Based on the comments of the participants in the proceeding as well as Merrimack Energy's view of the key RFP issues based on review of the Draft 2016 RFP and associated documents, the following issues are addressed: (1) Comparability of third-party bids and utility-owned resources; (2) Benchmark Bids; (3) Bid Evaluation Methodology; (4) Calculation of the Price Score; (5) Credit; (6) Resource Alternatives; (7) Transmission Costs/Assessment; (8) Accounting; (9) Resource Eligibility/Coal Option; (10) Indexing; (11) Other Cost Components; (12) Bid Categories; (13) 10% Price Increase Between Indicative Bid and Best and Final Offer; (14) Schedule; (15) Term Sheets; (16) Economic Evaluation Methods and Methodology. Each issue is discussed in some detail below. In addition, Merrimack Energy has also provided a red-line of the RFP document with specific comments on the provisions of the RFP as Appendix B.

A. Characteristics of any Effective Competitive Bidding Process

Based on its experience in several states, it is Merrimack Energy's view that any 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. Fairness in the process means that all bidders are treated the same. Also, for assessing the documents and information at this stage of the process, one of the key criteria 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, bid categories and alternatives, etc. that are allowed to compete in the process and the methods for evaluating and scoring the competing products.

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-resource and inter-resource 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. A robust response to a solicitation process is generally an indication that bidders feel the process is fair and they have a reasonable opportunity to effectively compete.

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.

<u>B. Utah Specific Competitive Factors</u>

The Energy Resource Procurement Act, codified at Utah Code §§ 54-17-101 et seq. (the "Act"), as applied to the facts of this RFP, controls this assessment by the IE. The Act creates a public interest standard for Commission review and approval of this Draft RFP in UCA § 54-17-201(2)(c)(ii) as follows:

> In ruling on the request for approval of a solicitation process, the commission shall determine whether the solicitation process:
> *   *   *
> (ii) is in the public interest taking into consideration:
> (A) whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in this state;
> (B) long-term and short-term impacts;
> (C) risk;
> (D) reliability;
> (E) financial impacts on the affected electrical utility; and
> (F) other factors determined by the commission to be relevant.

While the Act controls these proceedings, the context of this assessment is a Soliciting Utility which is subject to both a duty to serve and a duty of prudence in meeting its duty to serve. With respect to Commission rate-making, for example, see: UCA § 54-4-4(4)(a) (added by Senate Bill 26, 2005). Prudently implementing its duty to serve will require PacifiCorp to observe the Act, much as it observes all applicable permitting, licensing, rate-making and other laws. However, the duty to serve creates no preference for utility-owned resource options. To the contrary, the duty to serve requires a truly workable procurement process - - in compliance with the Act.

C.Comments on the PacifiCorp Draft RFP

Below is a compendium of our comments on PacifiCorp's 2016 Draft All Source RFP. The comments reflect the positions of the three interested parties who submitted comments, our own assessment based on a review of the 2016 Draft RFP as well as the lessons learned from the 2008 All Source RFP and other effective solicitation processes.

1. Comparability[4]

In order for the RFP process to satisfy the criteria for an effective and efficient competitive bidding process and produce a result that is in the public interest, all resource options should, to the greatest extent possible, be made directly comparable and put on an even footing or "level playing field" for evaluation and scoring purposes. UAE, in its comments, states that it hopes to see a meaningful evaluation by the IE on how well this RFP achieves comparability with respect to evaluation of different resource types.

Merrimack Energy recognizes the valid concerns about comparability raised by UAE and addressed by Merrimack Energy in its April 11, 2008 report on PacifiCorp's previous All Source RFP. In that report, Merrimack Energy provided a detailed assessment of different procurement models and options for achieving comparability. As we noted in our report on the 2008 All Source RFP, we view the comparability issue to be the most important and most complex issue in the design of competitive bidding processes. Unfortunately, there are no industry standards or valid working models that can be relied upon to ensure comparability in resource treatment. Merrimack Energy will not repeat the discussion here with regard to comparability of resource options but instead suggest that the April 11, 2008 Report of the Independent Evaluator Regarding PacifiCorp's All Source Request for Proposals be available as a reference in this regard.

As we concluded in the Final Report of the Utah Independent Evaluator for PacifiCorp All Source Request for Proposals Docket No. 07-035-94 and Docket No. 10-035-126, January 25, 2011, the 2008 All Source RFP took several important steps in the right direction in moving

[4] Comparability refers to the evaluation of power generating resources with different project structures and characteristics on a fair and consistent basis. For example, resources that will be owned by the utility will have a very different cost and risk structure that a Power Purchase or Tolling Services Agreement where the bidder submits essentially a firm price and must absorb the risks and benefits of changes in costs for the project relative to its contract pricing.

toward comparability for third-party Power Purchase and Tolling Service Agreements and cost of service options.[5] This includes:

- Index pricing for the capacity or capital cost component of the bid pricing formula;

- Contract provisions designed to balance risk in all contract options;

- Implementation of the two-stage pricing process (initial bid/best and final offer) designed to encourage bidders to provide a firm price in conjunction with their EPC contractor/suppliers by the time they submit the Best and Final Offer;[6]

- Pass through of change in law costs associated with meeting environmental requirements;

- Support for the position proposed by PacifiCorp to address imputed debt at the end of the selection process rather than include imputed debt as an evaluation factor;

- Support for PacifiCorp's proposal to allow bidders to phase-in the posting of security such that the majority of security would not be required until the Eligible online date. This would allow the bidder to incorporate the cost of security in their financing arrangements and would hopefully reduce the cost burden associated with the cost of security.

We feel these provisions have been a step in the right direction. In our comments in response to the Draft 2008 All Source RFP, Merrimack Energy also raised another area to achieve comparability and that is the issue of cost of maintaining financial security. For example, third-party bids are required to post development period and operating period security that is accessible to the utility to secure replacement power should the third-party bidder fail to meet its obligations under the contract, default under the contract, or experiences undue delay in achieving milestones under the contract. While EPC bids will be required to post some form of development security, since the utility will own the project there are no operating period security requirements. In this Draft 2016 All Source RFP, PacifiCorp has included the option for bidders to submit as an alternative different pricing/security structures under Proposal Options on Page 21 of the Draft RFP. The IE views this alternative as another step forward for achieving comparability.

[5] Although PacifiCorp has not offered a Self-Build Benchmark Option that the Company would construct if it is "winning" bid, such resource options as an EPC contract for a project on PacifiCorp's Currant Creek site or an APSA at a Bidder site or even at a Company site will still be a cost of service resource and thus subject to comparability principles.

[6] An important aspect of this process is that bidders will only be required to submit a best and final offer after selection for the short list. Thus, knowledgeable bidders can submit a higher level indicative bid price and work to firm up the price only if they are on the short list. This means that a firm price will be provided by the bidder when it is close to contract negotiations.

2. Benchmark Bids

Both the Office of Consumer Services and the Division raise concern about PacifiCorp's failure to include a benchmark bid in the RFP, as in past solicitations. By way of review, in previous solicitations the benchmark resource was generally based on a specific type of generating resource at a proposed site, with fairly detailed capital and operating cost estimates along with the operational parameters for the unit. PacifiCorp generally retained engineering consulting or pre-EPC type services to assist in preparing the costs of the benchmark. In the 2008 All Source RFP recently completed, PacifiCorp Energy actually solicited EPC bids for a project to be built on the Company's Lake Side site. Effectively, the Company EPC option ended up in direct competition with a third-party bid for an EPC, also at Lake Side. The level of effort undertaken by PacifiCorp Energy proved to be a costly endeavor. As a result, in this case, PacifiCorp is requesting EPC bids directly at a Company site, with the implicit objective that the EPC offers effectively replacing the benchmark option.

Benchmark resources can serve to meet several objectives. First, as PacifiCorp has done in the past, the benchmark could represent a resource that the Company would build in case it was the lowest cost or preferred option relative to the bids received in response to the RFP. Effectively, under this approach, the benchmark resource is the same or similar to an actual self-build resource competing directly against other options.

Another use of the benchmark is to set a "cost to beat" and use such information to decide on the appropriate course of action for the procurement option. In other words, a utility could use this information to conclude that the bids received are cost-effective or are not competitive offers based on their relationship to the benchmark.

While detailed EPC cost options at a Company owned site vetted through such a solicitation process such as the two-stage approach proposed by PacifiCorp could provide a reasonable resource alternative, the IE is concerned about the implications of such a process should only one or possibly two EPC bid be received. The question is whether or not the EPC option would result in an adequate and competitive bid to justify selecting the resource if the number of bids is limited, even if the EPC option proves to be the most cost competitive option relative to other resource alternatives. Without some type of benchmark costs, what is the appropriate process to make such a decision? In addition to aiding in the decision-making process regarding the resources proposed, the presence of a benchmark could also guide bidders on the preferred resource to consider and would provide transparency to the process

3. Bid Evaluation Methodology

On page 50 of the Draft RFP (Step 2 of the Evaluation process), PacifiCorp states that "resources not removed to create a capacity deficit, except for front office transactions, will be fixed for all portfolios to remove the impact of out-year resource optimization on bid resource selection." In its comments, the Division maintains, as it did in the Lake Side 2 proceeding (Docket No. 10-035-126), that fixing IRP resources in outer years of the study does not allow bidder proposals to potentially defer those IRP resources and, thus, may understate the total potential present value of the proposal. The Division cites the Commission's finding in the Order in Docket No. 10-035-

126 that the Division's recommendation to not fix any future IRP resources in evaluating the bids in future RFPs "had merit". The Division concludes in its comments that fixing post-2016 resources is a significant issue that the Commission should resolve in this Docket. The Division recommends that the Company not fix post-2016 resources in its bid evaluations.

In response to DPU Data Request 1.1, the Company stated that the Commission made no finding nor issued an order prohibiting the use of "fixed" generic resources in the evaluation process horizon. The Company also stated that no party at the workshop held on September 1, 2011 objected to the Company's proposed modifications to its evaluation process.

The IE's recollection from statements by a PacifiCorp representative at the hearings in Docket No. 10-035-126 was that PacifiCorp's representative indicated it was feasible to treat the generic future capacity units in the IRP as "floating" rather than "fixed" units and therefore allow for an optimized resource plan based on assessment of the proposed RFP bids. However, PacifiCorp apparently came to a different conclusion in preparing its RFP and proposed evaluation methodology as contained in its "Final Short List Development for the All Source Request for Proposals" Report.

Merrimack Energy has served as IE on a range of different solicitation processes with the use of different bid evaluation methodologies and assumptions. In our experience, the selection of the appropriate bid evaluation methodology is generally dependent on a number of factors including: (1) the time allotted to complete the analysis, (2) the expected number of bids and types of resources solicited, (3) the cost of conducting the evaluation (4) the methodologies and models utilized by the utility for its resource planning process, and (5) the goals and objectives of the solicitation process. For example, some utilities fix the resources in their resource plan and conduct detailed sensitivity analysis and risk analysis, as PacifiCorp has proposed. Other utilities allow the resources in the plan to float but do not conduct the same level of risk assessment or other sensitivity analysis. There are also a range of options in between the two cases mentioned above, with the methodology unique to the utility.

Merrimack Energy finds merit in the comments of the Division and the Office of Consumer Services regarding the bid evaluation methodology. The conclusion of PacifiCorp that the Commission Order does not prohibit the use of fixed generic resources in the evaluation process horizon merely ignores the Commission's finding that the Division's recommendations have merit. This RFP process is the appropriate forum to assess the merit of the appropriate methodology. Furthermore, no weight can be give to PacifiCorp's comments in response to DPU Data Request 1.1 since parties to the workshop were likely not in a position to draw a conclusion at that time. A No Comment response from bidders cannot be construed as acceptance of the methodology. As a result, the IE recommends that PacifiCorp prepare an analysis for review by the parties assessing the pros and cons of implementing a bid evaluation methodology consistent with its approach to fixed post-2016 resources relative to a methodology to allow such resources to float as a means of optimizing resource selection.

4. Calculation of the Price Score

In Section B.1 of Chapter 6 of the Draft 2016 RFP, PacifiCorp has revised the metric for determining the price score in Step 1 of the evaluation process. PacifiCorp states that the market ratio will be expressed as a percentage and calculated by dividing the PVRR of expected energy value into the PVRR of proposed costs. This new methodology apparently replaces the previous price evaluation metric which was the projected net present value revenue requirement per kW-month (Net PVRR/kW-month). Under this methodology, the net PVRR component views the value of the energy and capacity as a positive, and the offsetting costs as a negative. The larger the net PVRR, the more valuable the resource is the Company's customers.

Based on review of the Draft RFP, it is not clear in the description in the RFP whether or not the units for comparison are merely being changed from kW-months to Megawatt hours (MWh) or if the metric itself is being revised to only reflect the energy value as appears to be stated in the Draft RFP. Therefore, the IE requests that PacifiCorp provide a more detailed description of the methodology with examples of how the calculations will be derived.

5. Credit

Consistent with the recent 2008 All Source RFP, PacifiCorp has included its Credit Methodology and Credit Matrices as part of the RFP. UAE in its comments asks the IE to evaluate whether the credit requirements are appropriate, fair, and not unduly restrictive or punitive. As will be described below, the methodology used by PacifiCorp for establishing the level of credit required from bidders is largely unchanged from the previous RFP, which resulted in a robust response from the market. Furthermore, the methodology has accounted for the reduction in market prices and volatility due to the drop in gas prices and reduced price volatility. Furthermore, no bidder into the previous 2008 All Source RFP complained about the credit assurance levels imposed by PacifiCorp and no comments have been filed herein which are critical of the credit methodology.

PacifiCorp includes an Attachment in the RFP (Attachment 14: Credit Methodology) which describes in detail its credit methodology. PacifiCorp also uses the methodology described in this Attachment to provide credit matrices for various resource types. The level of security identified in the matrix is distinguished by the credit rating of the counterparty and the size of the project.

The Bidder is required to utilize the Credit Matrix to determine the estimated amount of credit assurances required for each Resource Alternative bid in each Resource Category. The Bidder is required to demonstrate the ability to post any required credit assurances in the form of a commitment letter from a proposed guarantor or from a financial institution that would be issuing a Letter of Credit. The Company will require each Bidder to provide the company with an acceptable letter (if applicable) twenty business days after the Bidder is notified that the bidder has been selected for the final short list.

The credit risk profile and amount of credit security to be provided will be determined based upon:

- The credit rating of the bidder and the entity providing credit assurances on behalf of the bidder if applicable.

- The size of the Resource Alternative
- The eligible on-line date
- The type of Resource
- The bid category (base load, intermediate, and summer peak)
- Term of the underlying contract

All bidders will receive a credit rating which will be used in determining the amount of any credit assurances to be posted. In addition, the level of security will depend on whether the resource is backed by a physical asset or not. For all resource that involve a physical asset with appropriate step-in rights, PacifiCorp views potential credit exposure as the cost it would incur in the event the resource failed to come on-line when expected. PacifiCorp believes it could take up to 12 months to either step in and complete the project or cause the project to be completed on its behalf. If failure occurred near the expected on-line date, PacifiCorp would have to procure energy in the open market at then prevailing market prices.

In determining the amount of security to be posted, a Credit Matrix for each Resource Alternative and each eligible on-line date is shown. Next, PacifiCorp applies its internal credit risk tolerance specific to this RFP to each potential credit exposure in every cell of the Credit Matrix. The results are the amounts of excess credit risk that PacifiCorp requests be secured through third-party guaranties, cash, letter of credit, or other collateral or combination thereof.

The credit posting schedule is also defined in the RFP. Basically, bidders are required to post only 10% of the amount of credit required upon contract execution or the date the contract is approved by the Utah Commission, whichever is later. The full amount of credit required has to be posted in increments up to 100% by the Eligible on-line date or Effective Date + 38 months.

A Bidder may select to either post the initial security, which must be in the form of cash or a letter of credit only, or alternatively, a Bidder may post the full amount of credit security using any form of security acceptable to PacifiCorp (e.g. a third-party guaranty).

Also, PacifiCorp has maintained the same requirement for bidders to provide their guaranty commitment letter. Within 20 days after the Bidder is notified by the Company that the Bidder has been selected for the Final Shortlist the Bidder will be required to provide any necessary guaranty commitment letter from the entity providing guaranty credit assurances on behalf of the Bidder and/or necessary letter of credit commitment letter from the financial institution providing letter of credit assurances.

Therefore, the IE concludes that PacifiCorp has developed and implemented an effective credit methodology. The methodology is generally consistent with the methodology used in the 2008 All Source RFP. Furthermore, with reductions in power and gas prices, the required levels of security were reduced to reflect market conditions. PacifiCorp has also provided bidders additional flexibility by delaying the date for which bidders will be required to post 100% of the security required.

6. Resource Alternatives

One of the revisions to the 2016 RFP relative to the 2008 RFP with regard to resource alternatives proposed by PacifiCorp is the elimination of an Asset Purchase and Sale Agreement ("APSA") on an identified PacifiCorp site. Instead, the RFP is including as an alternative an EPC option at a defined PacifiCorp site (Currant Creek).

As Merrimack Energy understands, the fundamental difference between an EPC option and an APSA is that with an APSA a third-party (be it a project developer or EPC contractor) would be responsible for project development activities while with an EPC, the utility would likely be involved in project development activities. To maximize the potential for competition at the Currant Creek site, the IE recommends that PacifiCorp consider allowing both EPC and APSA options to bid. The scope of the development opportunities for the APSA bidders would need to be defined further by PacifiCorp listing those development tasks allocated to the Owner for Currant Creek 2 that have not yet been accomplished. These development tasks would be specifically differentiated from the permit responsibilities that are already assigned to the EPC Contractor under the form EPC agreement. If PacifiCorp provides a listing of unperformed development tasks and a listing of EPC permit duties, it will be easier to determine how much value could be added by an APSA developer and whether, as a result, adding this bidding flexibility is worthwhile.

7. Transmission Costs/Assessment

The RFP contains a number of revisions to Section 5.C pertaining to the allowable delivery points in both PACE and PACW as well as clarifying the impacts of transmission line construction on the timing for project in-service dates. It has been our experience in other conventional generation and renewable generation solicitation processes that transmission cost impacts, transmission access and interconnection issues are among the most complex to address in an RFP process. Merrimack Energy had previously suggested in other RFPs that PacifiCorp Transmission Department conduct a workshop for bidders to explain the transmission process and Attachment 13 (now Attachment 20) costs. PacifiCorp has stated that if prospective bidders submit a request for another transmission workshop PacifiCorp will hold a workshop prior to submission of bids. Given the importance of transmission on project viability and costs and the revisions in the RFP pertaining to delivery points and transmission system construction, the IE strongly encourages PacifiCorp to hold another Transmission Workshop for Bidders for the 2016 All Source RFP. The IE suggests the workshop be held either the same day as the Bidder's Conference after issuance of the Final RFP or the day following the Bidders Conference to allow prospective bidders to attend both workshops.

8. Accounting

Section 3.H.5 dealing with accounting issues, such as consolidation, is unchanged from the previous RFP. However, the IE is aware that the FASB Financial Accounting Standards referenced in the footnotes to that section may not be the latest standards. It is our understanding that FASB ("ASC") Topic 810 (Consolidation), FASB ASC 820 and FASB ASC 840 are more recent initiatives addressing consolidation and lease accounting. The IE requests PacifiCorp to verify that the footnote references included in this section of the RFP are still accurate. Should this not be the case, the IE requests that PacifiCorp either change the appropriate reference or make any necessary revisions to this section to reflect the accounting changes.

9. Resource Eligibility – Coal Options

Both UAE and the Division raise issues about PacifiCorp's proposal to limit coal resources to contracts with terms of 1-5 years, based on the requirements of other states. The Division states that on the surface this appears to be an absolute rejection of any coal resource bids into the 2016 RFP. The Division also identifies sections of the RFP that appear to imply coal resources will be considered. The Division concludes that the Company needs to be more specific about the circumstances under which a coal resource could be genuinely considered in the 2016 RFP. If the Company would accept a coal-based proposal under an exception, then it needs to clearly include this fact in the exceptions sections. If the Company really will not consider a coal resource under any circumstances, it should state that clearly as well. Again, the Company, bidders, Independent Evaluator, and regulators should not spend their time and effort with bids the Company essentially will not consider. UAE concludes that if coal resources are restricted to contract terms of 1-5 years, this restriction will likely ensure that coal resources have no possibility of meaningful participation in this RFP. As a result, the system may be deprived of the lowest cost resource. UAE submits that coal resources should be permitted to bid into the RFP without restrictions.

The IE is in general agreement with the Division and UAE. If bids for coal resources are limited to terms of 1-5 years, the only coal-based option is a PPA from an existing coal resource. Certainly, new coal-based options can't compete in this process. Assuming PacifiCorp includes all costs for a resource in its evaluation and evaluates all bids consistently within that evaluation process all resource options that meet the resource attributes (i.e. unit contingent or firm resource capacity capable of being dispatched) identified in the RFP should be eligible to bid. The bid evaluation methodology should be able to effectively distinguish the preferred resources based on the input assumptions and evaluation criteria.

For the 2008 All Source RFP, PacifiCorp prepared and issued two RFP, one for Utah and one for Oregon. Bidders could bid new or existing coal-based resources into the Utah RFP. The IE suggests PacifiCorp consider a similar approach for the 2016 All Source RFP.

10. Indexing

PacifiCorp has proposed to eliminate the option for Bidders to not only index the capacity portion of their bid price or the capital cost in the case of an EPC contract or APSA but also to extend the elimination of any form of indexing to Fixed and Variable Operations and Maintenance (O&M) costs as well.

While PacifiCorp argues that no Bidders that made the short list used the allowable indexing option with up to 40% of the capital or capacity costs potentially subject to indexing, there is no justification given for eliminating the option for indexing of fixed and variable O&M costs, which have traditionally been subject to variations due to inflation, wages or other such costs. In our experience, most utility solicitation processes allow such cost to vary with at least an inflation index.

The Division concluded in its comments that the Company should include the option to allow for limited inflationary adjustments in order to not potentially discourage bidders and cites the historical support in Utah for indexing as justification to reinstate the indexing component in the 2016 RFP.

Merrimack Energy believes there are two important distinctions that need to be addressed with regard to indexing:

1. The application of indexing for capital related or capacity related costs for all bid options;

2. The application of indexing for Fixed and Variable O&M costs.

From the perspective of indexing for capacity or capital related costs, the motivation for allowing bidders the option to include limited indexing was to both address the volatility and uncertainty in capital related costs and to also achieve comparability between utility-owned cost of service based projects and third-party projects (e.g. PPA, TSA or APSA bids). While a self-build option could make a case that if capital costs ended up being higher than the cost estimate due to unforeseen market events and therefore such costs were prudently incurred and should be recovered, third-party bidders had to bid a fixed price and could not adjust their prices due to higher capital costs. Allowing all options to utilize some form of indexing moves toward comparability of resource options and provides a hedge against price risk in the bid price with the intent that third-party bidders would not have to price in such risk when they submit their bids and face more difficult competition relative to utility cost-of-service options.

While PacifiCorp has taken other measures in the RFP to limit the value of indexing capital costs (i.e. the two stage indicative bid and best and final offer process should lead to firmer prices and less risk in capital costs at the best and final offer stage), Merrimack Energy believes the elimination of indexing for O&M costs and the requirement that bidders offer a fixed cost or fixed cost with the option for fixed escalation in the case of Variable O&M costs creates significant risk for PPA and TSA bidders in particular. As noted above, O&M costs are comprised of such costs as labor, consumables, and other costs that vary with market conditions and inflationary pressures. Requiring bidders to fix these costs results in pricing that is not sensitive to how such costs would be incurred. This would shift risk onto these Bidders as well as the Company, who would presumably have to subject their own costs to operate and maintain the EPC option to the same conditions, should it be successful. The risk of inflation or other costs that are not accounted for in the pricing formula would either discourage a bidder from submitting a bid or lead the bidder to price in the risk, all leading to higher costs and issues with comparability of resource evaluation.

Merrimack Energy recommends that PacifiCorp be required to reinstate indexing for both capital/capacity related costs as well as Fixed and Variable O&M costs to allow bidders to reflect the cost structure and market risk in their pricing formulas. Even if the Commission decides to approve PacifiCorp's proposal to eliminate the indexing option from capital or capacity related costs, indexing for O&M costs should definitely be reinstituted.

11. Other Cost Components

As noted in Issue 9 above, PacifiCorp made several changes to Sections 5.A.and 5.B. of the RFP associated with revisions to pricing components. In addition to the proposed revisions to indexing certain cost components for a power generation project, PacifiCorp has eliminated references to two specific cost categories – transport costs, including fuel pipeline charges and other costs such as property taxes, sales tax, and insurance payments. In the 2008 All Source RFP, Bidders had the option of identifying these costs specifically or including such costs in capacity or O&M. In Merrimack Energy's view the RFP should identify such costs and indicate that bidders should include these costs either in the capacity, fixed O&M or variable O&M components of their bid price and should identify which component of the pricing proposal such costs are included. This will ensure that all relevant costs are included in and identified in the pricing proposal.

12. Bid Categories

Similar to the 2008 All Source RFP, the Company will consider Resource Alternatives proposed by the Bidder in one of three Bid Categories:

(1) Base Load Bid Category: a Resource Alternative likely to exhibit a capacity factor at or above 60% over the proposed term;

(2) Intermediate Load Bid Category: a Resource Alternative likely to exhibit a capacity factor between 20% and 60% over the proposed term;

(3) Summer Peak Q3

In the 2008 All Source RFP, a few bids appeared uncertain into which category they would be included but had to specify a category. This appeared to be an issue particularly for existing units. While most bidders can probably render a "quess" with regard to which category they would belong based on their capacity factor over the proposed term, there is still some uncertainty on the part of bidders who may not be aware how their project will be operated within the PacifiCorp system over the 20 year contract term.

To eliminate "guess work" on the part of the bidder, Merrimack Energy suggests PacifiCorp consider the following revisions with regard to this issue in the RFP:

- Don't require bidders to identify the bid category in which they would be evaluated and instead allow the evaluation process to decide the category for the bid in Step 1 based on the estimated capacity factor of the unit over the contract term based on the modeling results;

- Provide bidders the option under Proposal Options on page 21 of the Draft RFP to select whether they want their bid to be evaluated in each Bid Category based on payment of the appropriate fee. Currently, footnote 7 on page 9 of the Draft RFP states that Bidders can propose the same Resource Alternative into more than one Bid Category; however, for purposes of this RFP, proposals bid into more than one Bid Category will be required to submit a bid fee for each Bid Category proposed. The Initial Shortlist will be developed for each of the three Bid Categories identified in this RFP.

In the view of the IE, PacifiCorp's approach included in Footnote 7 unduly penalizes bidders relative to the effort required to undertake this assessment. Under PacifiCorp's approach, a bidder will be required to post a bid fee of an additional $10,000 if it wants its bid evaluated within both the Base Load and Intermediate categories. Instead of this approach, we recommend PacifiCorp consider each of the options identified above. PacifiCorp is in a much better position based on its knowledge of its system and modeling capabilities to determine if a particular proposal will operate at a greater than 60% capacity factor or between 20-60% based on its heat rate and variable fuel and operating costs.

<u>13. 10% Price Increase Limit Between Indicative Bid and Best and Final Offer</u>

PacifiCorp has maintained the same 10% limit for Bidders to increase their price from their indicative bid offer to the best and final offer in the 2016 RFP. While the IE has no issues with the 10% limit associated with a potential price increase in the bid from indicative bid to best and final offer, Merrimack Energy recommends that the methodology used by PacifiCorp to assess the basis of whether a bid violates the 10% limit (i.e. fixed costs only can increase by no more than 10% or all costs can increase by no more than 10%) be further defined in the RFP. This will provide guidance to bidders in developing their indicative bid and best and final offers and avoid the prospect of bidder uncertainty and complaints if they are reasonably rejected for violating the 10% cost limit.

<u>14. Schedule</u>

The IE has some concerns with the schedule proposed by PacifiCorp for the solicitation process. The proposed schedule is different for several important milestones than the schedule for the 2008 All Source RFP that the IE felt was an effective process. For example, the 2008 RFP allowed four months from the time of issuance of the RFP until the Bid Due date. The 2016 RFP allots nearly five months. The 2008 RFP allotted nearly three months from receipt of bids to selection of the short list. The 2016 RFP allots approximately six weeks. Finally, the 2008 RFP allowed over six weeks from the selection of the short list to receipt of best and final offers. The 2016 RFP allows only 4 weeks.

The IE has a few suggested changes in the schedule to provide a more realistic schedule for completing the evaluation while providing best and final bidders a greater opportunity to firm up prices. First, the IE recommends that three and one-half to four months be allotted for submission of a proposal after issuance of the RFP. Assuming issuance of the RFP on January 5, 2012, the due date for submission of bids should be on or about April 24, 2012. Second, the IE suggests that PacifiCorp allow more time for the evaluation of proposals to select a short list. In the past, PacifiCorp has conducted an initial review of the bids and worked with bidders to develop a term sheet to ensure the Company and the bidders agree on the key bid parameters. The time to undertake this task has been 4-6 weeks. While the IE has suggested that the time to complete this task should be reduced, the IE is still skeptical that the Step 1 evaluation can be completed in six weeks. Therefore, the IE recommends that PacifiCorp allow two months for completion of this task or until on or about June 25, 2012. Third, the IE suggests providing six weeks for short listed bidders to prepare a best and final offer and to firm up their prices. As a result, the scheduled date for submission of Best and Final offers of August 8, 2012 can be maintained, but the schedule for tasks from issuance of the RFP to the Best and Final offer should be revised.

15. Term Sheets

PacifiCorp has included the Model Term Sheet as Attachment 19 to the RFP. The IE views the inclusion of the Term Sheet as a positive addition to the RFP. In addition, the RFP addresses the completion of the term sheet as a task in Section 6A (Overview of the Evaluation Process). This should serve to guide the bidders about the importance of completion of the Term Sheet and should reduce the time for completing the short list evaluation process.

16. 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 2016 Draft RFP, PacifiCorp indicates that it will use the same models and methodologies it used in the 2008 All Source RFP competitive bidding process. PacifiCorp will therefore 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.

In the 2008 All Source RFP, the IE was directly provided the model results each step in the evaluation process from PacifiCorp via flash drives, which allowed for a thorough analysis of the model results for each bid. In addition, PacifiCorp prepared reports at each step in the process detailing the results, which the IE found particularly helpful. We presume that process will be maintained in this RFP as well. It should be noted that the IE has become quite familiar with the models and methodologies used by PacifiCorp based on the past few RFPs in which we have served as IE.

The IE's focus with regard to the models is to ensure the modeling approach and assumptions used do not create any undue biases favoring any resource alternative, that the methodologies are consistent with industry standards, and that the methodologies produce consistent results.

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 three models for this process. The modeling steps in the process include: (1) In Step 1the RFP Base Model will be applied at the initial screening phase of the evaluation; (2) In Step 2, Ventyx Energy LLC's System Optimizer Model (System Optimizer) will be used to develop optimized portfolios from the initial short-list under various assumptions for future emission expense levels and market prices; (3) In Step 3, the Planning and Risk Model (PaR) will be used in stochastic mode to develop expected PVRR and risk measures for the optimal portfolios developed from the System Optimizer model in Step 2; and (4) Also in Step 3 the optimal portfolios will be subjected to a more in-depth deterministic dispatch using System Optimizer, with each portfolio being assessed for each of the future scenarios described in Step 2 above.

Based on our previous experiences with the bid evaluation models (i.e. RFP Base Model and Production Cost Models) and their results, meetings with PacifiCorp staff to discuss the model methodologies and applications, and industry standards from other RFP processes, the IE previously concluded that the methodologies proposed by PacifiCorp are reasonable and should result in fair and equitable modeling 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. Merrimack Energy will review the model structures as required, notably the Base Model, the model results, and all input assumptions as part of our assignment as IE. At this point in time, we cannot opine on any revisions to the models, particularly the Base Model, until we begin to review any such revisions.

VI. Assessment of the Contract Risk Issues

The differences in the pro forma contracts in the 2016 Draft RFP from the pro forma contracts in the earlier RFP's relate primarily to the EPC agreement.[7] As a result, the EPC agreement will be compared here with PPAs and the risk characteristics between the two will be noted below.[8] In this regard, the IE has again assessed the forms to determine whether there are any undue biases in the form contracts that could favor one type of resource option over another. However, unlike the 2008 All Source RFP, in the present case, no benchmark options are being proposed. Accordingly, to assess the fairness of the RFP, the IE points out in this section how each of the major project risk characteristics is captured in the two principal pro forma contracts being reviewed.

Elsewhere in this report, the IE comments on the absence of the benchmark options in this 2016 Draft All Source RFP. As to risk characteristics, however, it must be noted that the absence of the benchmark options does not entirely eliminate the higher risks to ratepayers which, at least in theory and without regard to the possible mitigating impacts of prudence reviews, fall on ratepayers under the traditional cost of service pricing principles that still attend the EPC option. Owner costs, which will be capitalized along with costs incurred under the EPC agreement, are not being fixed when the EPC option is selected. The costs expected to be incurred under the EPC agreement itself can also increase since the form of agreement is much more flexible than PPAs in allowing increases under its Change in Work and other provisions. Moreover, operating costs are not fixed or set by any formula after construction.[9] Accordingly, traditional cost of service pricing principles will apply to these components of life cycle costs when the EPC option is selected.

A. Risk Allocation between Seller and Buyer in the Form Contracts: Issue by Issue Comparison among Power Purchase Agreement (PPA) (Attachment 3) and Engineering, Procurement and Construction Contract (EPC) (Attachment 4)

[7] Minor changes have occurred to the APSA which relate to the elimination of PacifiCorp sites from the scope of its planned application. PPAs are no longer allowed on PacifiCorp sites as well. The rationale for disallowing these forms of resource options at Currant Creek 2 has not been explained in the Draft All Source RFP for 2016 Resources.

[8] The Tolling Service Agreement (TSA) shares a common foundation in the forms and can be described as a PPA without fuel service. The Engineering, Construction and Procurement Agreement (EPC) shares a common foundation in the forms with the APSA. The APSA incorporates development and permitting duties and shows minor changes from prior versions of the APSA which are noted above. Changes to the EPC indicate that the form has matured through the negotiation process that attended its use with one or more actual projects. Since the EPC agreement is now more mature and EPC bids for the Currant Creek 2 site can be expected, a comparison of the PPA and the EPC forms should be sufficient to illustrate the salient differences between the two categories of forms: third party product delivery and service agreements (PPAs and TSAs) and owner asset procurement and acquisition agreements (EPCs and APSAs).

[9] In fact, Attachment 16 to the Draft All Source RFP for 2016 Resources provides a Term Sheet for O&M contracts that might be applicable to APSA Sellers but does not appear to be applicable to EPC Sellers at all. In any event, few details are given how the performance standards outlined in the Term Sheet would be fashioned and how they would be enforced.

1. Milestone, Development and Completion Risk. Both PPA Sellers and EPC Contractors 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 (six specific Milestones leading up to and including the Commercial Operation Date), 2.3 (Daily Delay Damages), 10.1.2.4 (milestone failures), 10.1.2.5 (COD failure) and 10.2 (termination) of the PPA. See, also, Sections 4.5 (Contractor Acquired Permits), 4.17 (all technical support and information to enable Owner to obtain Owner Acquired Permits), 4.29 (Critical Path Schedule), 8.2 (Substantial Completion Guaranteed Date), 8.3 (Schedule Recovery Plan), 16.2 (Liquidated Damages for Delay in Substantial Completion),[10] 20.1(g) (failure of Schedule Recovery Plan), 20.1(i) (Substantial Completion delay) of the EPC.

While the Owner plays a significant role in developing a project to be sited on its own land,[11] under the form of EPC agreement in the RFP, EPC Contractors also play a significant role in the overall development of the project. In this regard, Contractor Acquired Permits are significant and extensive.[12] Moreover, EPC Contractors have a significant support responsibility with respect to the Owner Acquired Permits (see: Section 4.17). Unexcused delays could originate from an unexcused failure to obtain Contractor Acquired Permits or to provide timely and adequate support to Owner in obtaining the latter's assigned permits. At least potentially, EPC Contractors may have significant development duties with respect to permits, while still not enough to rival the all-inclusive duties of PPA Sellers to obtain permits.

On the other hand, EPC Contractors enjoy more flexibility in their performance than do PPA Sellers due to differences in the scheduling and permit provisions of the subject forms. In particular, Section 4.29 requires the EPC Contractor to develop a series of Critical Path Schedules but only two specific milestones are set forth in Exhibit J, the Mechanical Completion and the Substantial Completion Dates. The other 60 Contractor Milestones are to be agreed to later and Section 8.3 allows the EPC Contractor to create a Schedule Recovery Plan when Critical Path Items are missed. The Force Majeure definition in Section 1.56 allows certain permit difficulties to qualify as Force Majeure. Furthermore, Article 17 of the EPC contemplates a large number of occasions which can result in a change to Project Schedule without penalty to the EPC Contractor (Section 17.1, 17.3 and 17.4). For example, if the requirements of an Owner Acquired Permit change, a Change in Law occurs, materially different subsurface conditions are encountered, existing hazardous materials at the site are more significant than anticipated or qualifying events of Force Majeure occur, and the EPC Seller is actually and

[10] Please note that the text of Section 16.3 is identical to Section 16.2, an apparent editing error.

[11] Appendix Q to Exhibit A contains the Schedule of Permits and Governmental Approvals for the Currant Creek 2 project. Owner has responsibility for the various air permits, for the Hazardous Waste Generator ID, the operations Spill Prevention Control and Countermeasure Plan, the Threatened and Endangered Species Review, the Flood Plane Re-designation, the Local Site Plan approval, the DOE registration, operating DOT requirements, PUC approvals, the Utah NPDES for operating wastewater disposal, water rights transfers and the operating Stormwater Control Plan.

[12] Most of the other permits listed in the 8-page Appendix Q to Exhibit A, i.e., those not listed in the prior footnote, are the responsibility of the EPC Contractor. Note that the cross-reference to Appendix U in the definitions of Contractor Acquired Permits and Owner Acquired Permits in Sections 1.25 and 1.91, respectively, of the EPC form appears to be erroneous. Appendix U lists only the air permit data obtained by the Owner.

demonstrably delayed in the performance of a Critical Path Item, a Change in Work is possible at the request of the EPC Contractor. The Change in Work then could result in a extension of the Critical Path Schedule by the required amount of time to accommodate the delay (Sections 17.1 and 17.4).

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); however, bidders are allowed to propose an extension period after the deadline date before which any default comes into existence. In the PPA, there is also some meaningful relief from the default risk from the Force Majeure provisions dealing with permits and required documentation. EPC Contractors face a comparable “no notice and no opportunity to cure” risk of termination when the deadline for Substantial Completion is missed (an automatic extension of 120 days is drafted into the default definition in Section 20.1(i)) and, as described above, EPC Contractors can also get meaningful relief from such risk in the Force Majeure and scheduling provisions of the EPC.

Accordingly, since EPC Contractors enjoy more flexibility in their performance due to differences in the applicable schedule and permit provisions of the subject forms, the risk of milestone and development default and termination is higher for PPA Sellers than for EPC Contractors. See: Comments No. 2-4.

2. <u>Force Majeure and Permit Delays</u>. 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 allow permit delays to escape exclusion from the definition. The subject definition excludes “(v) delay or failure of Buyer to obtain any Required Facility Document **other than Permits** which Seller is diligently and timely taking all reasonable steps to obtain.” (Emphasis added.) 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, the limitation was needed to allow delay or failure of Seller to obtain its required permits to be an event of Force Majeure excusing a delay of Seller to meet its Milestone duties under Section 2.2. Such a Milestone failure can still, however, mature into a Seller Event of Default under Section 10.1.2.4 and 10.1.2.5, after 180 days, the limit to any Force Majeure event.

Under the EPC form of agreement, the definition of Force Majeure in Section 1.56 also contains some relief to the advantage of Seller. An exclusion is first stated but then qualified as follows: Force Majuere excludes “(iii) delay or failure by Contractor to obtain the requirement for or properly to apply for any Governmental Approval which is customarily obtained by Contractor in connection with the Work . . . **other than the delay or failure to obtain an Applicable Permit occasioned by** (x) revocation, stay, or similar action by a Governmental Authority 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) an event of Force Majeure.” (Emphasis added.) The exceptions to the exclusion mean that time-consuming appeals, governmental miscues and other Force Majeure events causing permit delay may result in excused permit failures.

Accordingly, while the provisions are not comparable, EPC Contractors may fare somewhat better in avoiding the risk of defaults due to delays in obtaining permits than do PPA Sellers which are entitled to 180 day relief from Milestone failures due to permit delay. EPC Buyers experience higher risks of uncompensated delays and cost increases as a result of the flexibility in performance accorded EPC Contractors. See: Comment No. 5, infra.

3. General Force Majeure Standard. In Section 1.56 of the EPC agreement, Force Majeure is defined with reference to a general standard, "an event not reasonably anticipated as of the Effective Date of this Agreement". Force Majeure is similarly defined in Section 13.1 of the PPA as "an event . . not reasonably anticipated as of the date of this Agreement. The EPC and PPA definitions are comparable with respect to the issue of anticipation of future events. A variety of other wording differences do exist between the two forms, mostly reflecting the difference in the character of the transaction. However, the most important of these differences is the exclusion for PPA Sellers from the Force Majeure standard of changes in the Environmental Laws or the cost of compliance with such laws (Section 13.1). Meanwhile, EPC Contractors enjoy the right to apply for a Change in Work for a broadly defined set of Change in the Law events that adversely affect the EPC Contractors' costs and schedule (Sections 1.16 and 17.4).

4. 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 PPA Buyer expects to execute. While PacifiCorp's actions as PPA Buyer affect the ability of the PPA Seller to obtain such financing documents, the PPA Seller remains at risk, without Force Majeure excuse, for any delay in satisfying its Section 2.2.3 Milestones duties for financing. Such a Milestone failure can then mature into a Seller Event of Default under Section 10.1.2.4 and 10.1.2.5. This risk for financing documentation is unique to the PPA option.

5. Force Majeure, Change in Law and other Bases for Cost Increases. The applicable provisions of the EPC agreement result in a risk that costs to EPC Buyers 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 Buyers under the PPA. Compare: Sections 5.1.2 and 6.3.1.1 of the PPA to Sections 17.1(d), 17.1(h) and 17.4 (b) of the EPC.[13] A variety of additional reasons exist in the EPC form for costs increases, such as changes in subsurface or hazardous materials conditions. See: Section 17.1.

[13] Section 17.5 of the EPC form seems to limit the ability of an event of Force Majeure to result in a change to Contract Price. This intent seems clear, but there is an apparent error in the "subject to" clause in Section 17.4(b) which presumably should refer to Section 17.5.

Under traditional cost of service principles applicable to the other aspects of the EPC option, events outside the control of the utility, including, in particular, changes in law, would not result in imprudence disallowances as long as the utility continued to adapt its development efforts to the changed circumstances in a prudent fashion. As a result, outside of the scope of the Work under the EPC agreement are all of the Owner's activities at the Premises which could result in cost increases beyond those originally estimated as the Owner's Costs. For example, for the Owner's activities, permit opposition and delay, changes in law relating to environmental control requirements, and other similar occurrences could result in prudently incurred delay and scope-change costs for the Owner's activities. Ratepayers have traditionally absorbed costs such as these which a prudent utility could not reasonably avoid. Thus, while there is no benchmark option in this RFP which is subject to cost of service principles, prudently incurred increases the Owner's scope at the Currant Creek 2 site will be passed on to ratepayers, in addition to increases in price allowed under the more flexible provisions of the EPC form itself.

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 to recover only cover damages between the reference market price for replacement power at a specified location and the contract price.

Under Section 16.2 of the EPC agreement, Seller is required to pay daily Substantial Completion Delay Liquidated Damages ($140,000 per day for the first 31 days and $230,000 per day thereafter).

In the case of both PPAs and EPCs, the delay damages collected from Sellers are available to offset the losses incurred by Buyers when replacement power must be purchased due to the late completion of the PPA and EPC projects. For EPC agreements, however, the fixed amount of damages is unlikely to be correlated with excess replacement power costs. In fact, the Delay LDs are likely to be based on the extra carrying costs expected to be incurred by the Owner due to its inability to put the completed project into service where it would produce power and earn the Owner the right to recovery in rates for the project's capital costs. The EPC Delay LDs thus protect ratepayers from paying the extra capital costs associated with the delay, but do not address the replacement power costs during the delay period. Ratepayers fully absorb those costs. In addition, if delay occurs under the EPC agreement for reasons attributable to the Owner, the extra costs incurred by the EPC Contractor and the replacement power costs would both be transferred to ratepayers as long as the Owner was prudent in the actions responsible for the delay.

On the other hand, under the PPA, to the extent of such replacement power damages, ratepayers are in theory[14] protected from the excess cost of replacement power over the PPA cost of power. In addition, ratepayers are protected from the extra costs to complete

[14] The actual measure of protection would depend on the ratemaking conventions which determine how and to what extent replacement power costs are charged to ratepayers and how and to what extent damage revenues are credited to ratepayers.

the project since there is no right in the hands of the PPA Seller to raise the cost of power when it experiences increases in the cost to complete construction.

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. 5, for reasons of Force Majeure or Change in Law. This applies equally before and after the Commercial Operation Date.[15]

   Various provisions of the EPC agreement may, under certain circumstances, result in capital cost increases to EPC Buyers, and in turn to ratepayers taking service from such Buyers. Like most construction-based contractual forms, the EPC agreement contains Change in Work procedures such as Section 17 which contemplate price and other adjustments to the original contract terms. See, e.g., Sections 17.1(d) (Change in Law); 17.1(e)(Owner Caused Delay); 17.1(f)(Site Subsurface Condition); and 17.1(g) (Change in Work arising from Owner Hazardous Conditions); and 17.1(i) (Suspension of Work by Owner). Additionally, Section 4.35 can cause the cost to increase (Spare Parts available by Change in Work). Furthermore, during operation of projects by EPC Buyers, capital additions and retrofits would, except for warranty items, be at the risk and cost of EPC Buyers.

   Moreover, since the Work in Exhibit A does not comprise the entirety of the activities at the Premises, scope changes and/or cost increases that affect the Owner's activities can lead to an increase in the total cost of the project at the Premises. For the Owner's changes, prudence rules would apply, similar to changes in a Benchmark option. The Owner's ratepayers would be exposed to the cost increases that result from prudent changes in the scope of the Owner's work.

   Accordingly, EPC 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 that their monthly unexcused hours of unavailability exceed allowed margins. 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.

   Conversely, except for warranty defects enforced during the applicable warranty period (18 months in most cases) (see: Article 18), comparable risks for unavailability problems during the long period of operation of the Project do not exist for EPC Contractors. By

[15] Moreover, in this Draft 2016 RFP, the capital and fixed O&M indexing in the 2012 RFP has been dropped and only fixed capacity payments are allowed. Other more restrictive rules now apply to variable costs.

its terms, the EPC has been performed and is not longer in effect when the majority of the operating period under the PPA is occurring. In general, EPC Contractors bear no risk for replacement power costs since the product delivered under the EPC is a completed, properly functioning asset and not a power commodity over a long period of years. See: Section 20.3 of the EPC where the EPC Seller's primary liability for direct damages is described as the payment of the excess costs incurred by Buyer to complete the Project after terminating the EPC Contractor. See also: Section 20.2 where EPC 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[16].

Accordingly, EPC Contractors are exposed to little risk of replacement power costs and EPC Buyers have little protection from the risk of incurring full replacement power costs for their own account[17]. 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. <u>Energy Cost Escalation</u>. Under the present provisions of Section 5.2 and Exhibit F to the PPA as contained in the 2016 RFP, PPA Sellers are restricted to bidding Energy Payment formulae that conform to indices or fixed escalators.

In contrast to the PPA Buyers, EPC Buyers, as asset owners, will be exposed to the full risk of fuel market escalation[18]. EPC Contractors have no role in fuel purchasing which occurs after their performance is complete.

10. <u>Fuel Infrastructure and Electric Interconnection Costs</u>. The costs of the fuel infrastructure and the electric interconnection for the Projects are aspects of the capital cost of the Projects. As such, comments set forth in Comment No. 7 are equally applicable to fuel infrastructure and electric interconnection cost increases that are experienced after the Effective Date of the PPA or the EPC. Under Sections 5.1.2 and 6.3.1.1 of the PPA,

[16] Based on Attachment 16 to the Draft 2016 RFP, it is not clear that EPC Contractors may be required to enter into 10 year Operating and Maintenance Agreements in order to ensure cost effectiveness, availability and reliability of the resources prior to the Company's acceptance of the resource. Option 2 in Attachment 16 seems to apply and excuse EPC Contractors from O&M agreements due to the heavy involvement of PacifiCorp in the design of the Currant Creek 2 project. See: Attachment 17 (1,738 pages in length) to the Draft 2016 RFP. In any event, the terms and conditions of any such agreement are not given in any detail by PacifiCorp. To the contrary, the terms and conditions are only generally referred to in Attachment 16. Contract operators of power plants in general are reluctant to put at risk sufficient capital to cover replacement power costs when there are shortfalls in performance. Thus, it is far from clear that any 10 year O&M contract would ever put EPC Contractors on comparable terms with PPA Sellers. Such an outcome is considered unlikely.

[17] 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 EPCs are ultimately borne due to ratemaking rules or conventions by the shareholders or the customers of the utility.

[18] By ratemaking convention (net power cost modeling), Buyer's ratepayers will experience much of the actual fuel escalation. However, between rate cases, Buyer's shareholders will share in exposure to fuel price changes, which vary from the fuel price 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 ratepayers and Buyer risks actually experienced by shareholders.

payment formulae to PPA Sellers are not allowed to increase for any reason, including, for any change in the scope of the fuel infrastructure or the electric interconnection. Such changes could, however, result in capital cost increases to EPC Buyers.

Under traditional cost of service principles, provided that planning and construction exhibit prudence, EPC Owners, after the design of the Work in the EPC agreement is complete, can prudently experience capital cost increases for changes to the fuel infrastructure and/or the electric interconnection.[19] Such capital cost increases enter rate base if prudently incurred. Ratepayers are expected to absorb the risk of prudent capital cost increases.

11. <u>Lender Rights and Coordination</u>. 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 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 EPC Contractors (Article 7), there appear to be no references to lenders or financing parties which apply to EPC Contractors in the EPC agreement.

As in prior years, PacifiCorp added to the PPA a form of Lender's Consent. However, the document was not incorporated into the operative text of the PPA and it does not appear that PacifiCorp even agrees in the PPA to execute the Lender's Consent at any particular time or under any particular conditions. It is the understanding of the IE that the general absence of lender rights and lender coordination provisions in the PPA was intentional. However, PacifiCorp has previously acknowledged that in due course, before or after PPA execution, negotiation of intercreditor or subordination agreements could result in changes to the PPA or the PPA Buyer's rights and remedies thereunder. It is important to note that any delay in such negotiations after execution would be at the risk of PPA Sellers. See: Comment No. 4, above.

Here, based on the present PPA form, PPA Sellers will experience added risk in negotiating additional lender 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.

EPC Contractors experience no comparable risk.

In connection with its capitalization of the EPC agreement, PacifiCorp will be in regular negotiations with its lenders and its sources of equity (through its ultimate parent). Since no disclosure of PacifiCorp's plans, and estimated costs, to raise capital for the EPC option has been made to date, the IE is unable to assess the financial impacts on the affected utility for comparison or any other purposes. Provided that capital formation is prudently planned and implemented, ratepayers would be expected to incur all costs incurred in connection with raising capital for the EPC agreement.

[19] While all aspects of the interconnection appear to be within the EPC Contractors scope of Work (see: Exhibit A Statement of Work at pp. 8-5, 8-13, 8-15; and Appendix L), the Change in Work provisions in Section 17 of the EPC agreement can lead to cost increases in this part of the scope.

12. 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 (other than failure to achieve the Commercial Operation Date covered by Section 10.1.2.5). Section 10.1.2.4. However, of most importance, PPA Sellers, except for the 180 day Force Majeure relief early in the development period for permits, have no opportunity to avoid an Event of Default and to cure a failure to achieve the Commercial Operation Date by the extended date after the Guaranteed Commercial Operation Date, even if the Facility is then within days of completion. Section 10.1.2.5.

In comparison, for EPC Contractors, all milestone failures are covered by Section 20.1 (g) (failure to meet deadlines in a Schedule Recovery Plan) where a 60 day period of "grace" is provided; and by Section 20.1(i) (Substantial Completion Guaranteed Date) where there is an automatic 120 day "grace" period. Moreover, the provisions for Project Schedule revisions in Section 8.3 creates the prospect that milestones can be flexibly extended under a number of circumstances where a PPA Seller would have no relief (such as Change in Law).

Accordingly, PPA Sellers face higher risks of default and termination under the default provisions of the PPA than EPC Contractors face under the counterpart provisions of the EPC agreement.

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

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 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 comparison to benchmark options, the EPC form of asset acquisition agreement differs little in theory since the utility would invariably manage and control construction risks for the benchmark option by entering into some form of EPC agreement. Risks that costs depart from the "fixed" construction contract price for both the benchmark option and for the EPC option in this Draft 2016 RFP are generally expected to fall on ratepayers as long as costs which become "unfixed" were prudently incurred.

In simplified terms, the PPA internalizes many risks to which the owner of an asset resource 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 firmly 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 agreement, for a price, the risks of capital and other fixed cost increases from 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 some extent, fuel price changes, are largely accepted by PPA Sellers and largely avoided by PPA Buyers[20]. 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 EPC option in this Draft 2016 RFP in some ways mirrors the development period of the PPA since EPC Contractors here have assumed many permit and Owner-support duties, not all of which appear to be limited to the construction period. During the construction period itself, the EPC Contractor has comprehensive duties which rival the all-inclusive nature of the PPA Sellers’ duties. However, in this EPC agreement, as in many others in the industry, as comparable duties are performed, the transfer of risk to EPC Contractors is not as complete as in the case of the PPA - - more flexibility and tolerance for force majeure events, unexpected site conditions and changes in law are shown during construction and development than in the PPA. As well, EPC 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 EPC Contractors 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. As the actual owners, the EPC Buyers largely accept 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.

In summary, PPA Buyers are offered more cost protection from unanticipated changes than EPC Buyers. This protection applies even for changes that result in costs which are prudently incurred by PPA Sellers. EPC Buyers in many cases would absorb the same prudently incurred increases in cost. Protection comes at a price and overall PPA charges should be expected to be higher in typical projections of life cycle costs. Whether extra costs are absorbed later by EPC Buyers in amounts that exceed the originally higher estimates of PPA charges cannot be known at present.

[20] 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.

VIII. Conclusions and Recommendations

Based on our review of the 2016 All Source RFP and related information, the conclusions and recommendations of the IE related specifically to the 2016 RFP are presented in this section of the report.

- PacifiCorp has taken both positive and negative steps with regard to comparability of resources for evaluation purposes. On the positive side, PacifiCorp has included an alternative that allows bidders to provide pricing/security structures. In addition, PacifiCorp has provided additional flexibility and potential reduction in costs by providing a phase-in security posting schedule that reaches 100% of the security required by the eligible on-line date;

- PacifiCorp has proposed not offering a benchmark bid into the RFP, instead offering bidders the alternative to submit EPC bids at the existing Currant Creek site. While detailed EPC options at a Company site vetted through a solicitation process could provide a reasonable alternative to a utility benchmark, the IE is concerned about the prospect of only one or two EPC proposals being submitted. Another use of a benchmark resource is to establish a "cost to beat" if there is limited competition. The presence of such a benchmark can serve as a guide for PacifiCorp to decide whether to select a resource from the RFP;

- PacifiCorp has proposed to fix resources for all portfolios to remove the impact of out-year resource optimization on bid resource selection. The IE does not believe PacifiCorp has provided adequate justification to propose a fixed resource plan as a response to the Commission's statement that allowing future resources to float has "merit". The IE recommends that PacifiCorp provide an assessment of the pros and cons of conducting the evaluation process under the assumption of fixed versus floating future resource additions;

- PacifiCorp has revised the methodology and metric it has used in the past to calculate the price score in Step 1 of the evaluation process. The IE requests that PacifiCorp provide an explanation supporting the change in methodology and provide an example of the proposed metric for determining the price score;

- One issue that occurred in the 2008 All Source RFP process was that one bidder was eliminated because it violated the allowable 10% increase in bid price between the indicative bid and best and final offer. While all other bids met the 10% limit, the IE believes that PacifiCorp should clarify how the 10% limit will be calculated and applied;

- The Credit Methodology used by PacifiCorp is a sophisticated and reasonable process which continues to evolve. The credit methodology and credit matrix is largely consistent with the recent approach used by PacifiCorp for assessing the security requirements of bidders. The application of the methodology has resulted in a lower level of security required in the 2016 All Source RFP relative to the 2008 All Source RFP due to recent decrease in gas and power prices and lower price volatility;

- The 2016 All Source RFP contains a number of revisions to the allowable delivery points in both PACE and PACW as well as clarifying the impacts of transmission line construction on the timing of project in-service dates. Given the revisions in the RFP associated with transmission issues and the importance and complexity of transmission cost impacts and access, the IE recommends that PacifiCorp offer a Transmission workshop for bidders to coincide with the Bidders Conference after issuance of the final RFP;

- PacifiCorp has proposed to limit coal options to contract terms of 1-5 years. Based on this requirement, no new coal projects or even proposals for PPAs from existing coal resources would likely participate in the RFP, potentially removing a competitive resource option. The IE recommends that PacifiCorp issue two RFPs, similar to the 2008 All Source RFP, with coal treated as an eligible option for the Utah RFP;

- PacifiCorp has proposed several changes with regard to indexing of prices. First, PacifiCorp has proposed eliminating the option that all bidders had to index a portion of their capital cost or capacity prices to selected indices. PacifiCorp sites the fact that no bid on the short list for the 2008 All Source RFP selected any price indexing options for capital or capacity-related costs. Second, PacifiCorp also proposed to eliminate indexing for both fixed and variable operations and maintenance costs. The IE recommends that PacifiCorp be required to reinstate indexing for both capital/capacity related costs as well as fixed and variable operation and maintenance costs to allow bidders to reflect the cost structure and market risk in their pricing formulas, Even if the Commission decides to approve PacifiCorp's proposal to eliminate indexing of capital and capacity related costs, indexing for operation and maintenance costs should definitely be reinstituted;

- The IE has some concerns with the proposed schedule for the 2016 All Source RFP. In particular, PacifiCorp proposes a longer period between the time of issuance of the RFP and the due date for bids. As a result, the time allotted to complete the short list evaluation and the time for preparing a best and final offer has been reduced. The IE has proposed a slightly revised schedule designed to provide addition time for the bid evaluation and best and final offer but reduces the time available to prepare the initial bid to be consistent with the 2008 All Source RFP;

- PPA Buyers are offered more cost protection from unanticipated changes than EPC Buyers. This protection applies even for changes that result in costs which are prudently incurred by PPA Sellers. EPC Buyers in many cases would absorb the same prudently incurred increases in cost. Protection comes at a price and overall PPA charges should be expected to be higher in typical projections of life cycle costs. Whether extra costs are absorbed later by EPC Buyers in amounts that exceed the originally higher estimates of PPA charges cannot be known at present;

- As noted, PacifiCorp did not include a Code of Conduct with the RFP. The IE believes that PacifiCorp should include a Code of Conduct as in previous RFPs since the EPC option will be built on a PacifiCorp site.

Appendix A

Roles and Approach of the Independent Evaluator

A. Requirements for an Independent Evaluator

Rule R746-420, Request for Approval of a Solicitation Process provides a detailed description of the role of the Independent Evaluator (IE), the required qualifications for the Independent Evaluator, payments to the Independent Evaluator and the functions of the Independent Evaluator. The list of activities and functions of the Independent Evaluator as outlined in Rule R746-420 provide the overriding requirements for the Independent Evaluation in the solicitation process. This Chapter will list the functions and requirements for purposes of identifying the duties and roles of the IE throughout this process.

B. Activities 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. On a high level basis, specific objectives include the following:

- 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 has reviewed the RFP documentation in detail, and reviewed and evaluated the attached contracts and other arrangements. In addition, the IE has reviewed and assessed the evaluation criteria used to assess bids at all stages of the process, the models and methodologies underlying the pricing assessment, the evaluation and selection process and the overall process for bid evaluation, selection and contract negotiations. These models and methodologies are largely consistent with the models, methodologies and processes used in the previous RFP process.

C. Scope of Work of the Independent Evaluator

PacifiCorp has included Attachment 4 (Role and Function of the Independent Evaluators and Communication Protocols) in the RFP, which describes the roles for the Independent Evaluators. The role of the Independent Evaluator as described by PacifiCorp is consistent with the requirements for the IE listed in the Utah Energy Resource Procurement Act and Rule R746-420. Any differences are highlighted in this section. The four major functional areas for the IEs as listed in Attachment 4 include:

1. Overall role and function of the Independent Evaluator

2. The manner in which communications between the IEs, the Company and the Bidders should be conducted

3. Reporting process for the Independent Evaluators

4. Communications between the Evaluation Team and the Company Self-Build Team

The scope of work is consistent with Rule R746-420 implementing S.B. 26. A brief summary of the roles identified by PacifiCorp include:

D. Roles and Functions of the Independent Evaluators

- Facilitate and monitor communications between the soliciting utility and bidders.
- Review and validate the assumptions and calculations of any Benchmark Option.
- Analyze the Benchmark Option for reasonableness and consistency with the solicitation process.
- Access all important models to validate modeling techniques, assumptions, inputs and bid evaluation by the soliciting utility in the solicitation process.
- Receive and blind bid responses.
- Provide input to the soliciting utility on aspects of the competitive bidding process, including (1) development of screening and evaluation criteria, ranking factors, and evaluation methodologies that are reasonably designed to ensure that the solicitation process is fair, reasonable, and in the public interest in preparing a solicitation and in evaluating bids; (2) the development of initial screening and evaluation criteria that take into consideration the assumptions included in the soliciting utility's most recent IRP, any recently filed IRP update, any Commission Order on the IRP or IRP update and in its Benchmark options; (3) whether a bidder has met the criteria specified in any RFQ and whether to reject or accept non-conforming RFQ responses; (4) whether and when data and information should be distributed to bidders because it is necessary to facilitate a fair and reasonable competitive bidding process or has been reasonably requested by bidders; (5) negotiations of proposed contracts with successful bidders; and (6) other matters as appropriate in performing the duties of the Independent Evaluator under the Act and Commission rules, or as directed by the Commission.
- Ensure that all bids are treated in a fair and non-discriminatory manner.
- Monitor, observe, validate and offer feedback to the Soliciting Utility, Commission and Division on all aspects of the solicitation process, including (1) content of the solicitation; (2) evaluation and ranking of bid responses; (3) creation of the short list, post bid

discussions and negotiations, and (4) negotiations of the proposed contracts with successful bidders.

- Evaluate the unique risks and advantages associated with any Company Self-Build bid, including the regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected for the RFP.
- Once the competing bids have been evaluated by the Soliciting Utility and IEs, the Soliciting Utility and the IEs will compare results.
- Offer feedback to the Soliciting Utility on possible adjustments to the scope or nature of the solicitation or requested resources in light of bid responses received.
- Solicit additional information on Bids necessary for screening and evaluation purposes.
- Advise the Commission of any unresolved disputes or concerns at all stages of the process that could affect the integrity of the process.
- Analyze and attempt to mediate any disputes between the utility and bidders and present recommendations to the Commission for resolution of unresolved disputes to the Commission.
- Participate in and testify at Commission hearings on approval of the solicitation process and/or acknowledgement of the short list.
- Coordinate as appropriate and as directed by the Commission with staff or evaluators designated by regulatory authorities from other states served by the soliciting utility.
- Perform such other tasks as the Commission may direct.

E. Manner of Communication Between the IEs, the Company and the Bidders

- The soliciting utility may not communicate with any bidder regarding the solicitation process, the content of the solicitation or solicitation documents, or the substance of any potential response by a bidder to the solicitation, except through or in the presence of the IEs.
- The soliciting utility shall provide timely and accurate responses to any request from the IEs, including requests from Bidders submitted by the IEs, for information regarding any aspect of the solicitation or the solicitation process.
- Communications between a soliciting utility and potential or actual bidders shall be conducted only through or in the presence of the Independent Evaluator. Bidder questions and soliciting utility or IE responses shall be posted on an appropriate website. The IE shall protect or redact competitively sensitive information from such questions or responses to the extent necessary.

G. Reporting by the IE

The IE shall prepare at least the following confidential reports and provide them to the Regulators and the soliciting utility:

- Monthly progress reports on all aspects of the solicitation process as it progresses.
- Final Report as soon as possible following the completion of the solicitation process. Final reports shall include analyses of the solicitation, the solicitation process, the soliciting utility's evaluation and selection of bids and resources, the final results and whether the selected resources are in the public interest.

- Other reports the IE deems appropriate, and
- Other reports as the Commission may direct.

The IE shall prepare at least the following public reports and provide them to the Commission, interested parties and the soliciting utility:

- Final Report, without confidential information, analyzing the solicitation, the solicitation process, the soliciting utility's evaluation and selection of bids and resources, the final results and whether the selected resources are in the public interest.
- Comments and recommendations with respect to changes or improvements for a future solicitation process.
- Other reports as the Commission may direct.

<u>H. Communications Between the Evaluation Team and Company Self-Build</u>

- The Evaluation Team, including the non-blinded personnel, may not be members of the Company Self-Build Team, nor communicate with members of the team during the solicitation process.
- The exception is that internal company attorneys and credit analysis personnel may deliver legal or credit advice, as applicable, to either or both teams.
- The IEs must participate in any communications between members of the Company Self-Build Team and the Evaluation Team and must retain a copy of all such correspondence to be made available in further Commission proceedings.
- There shall be no communications regarding the blinded bid information between the non-blinded personnel and other evaluation team members until the final short list is determined, which communication shall be done in the presence of the IE.
- The Evaluation Team shall have no direct or indirect contact or communication with any Bidder other than through the IE until such time as a final shortlist is selected by the soliciting utility.
- Should any Bidder or a member of the Company Self-build team attempt to contact a member of the Evaluation Team, such Bidder or member of the Company Self-Build Team shall be directed to the IE for all information and such communication shall promptly be reported to the IE by the Evaluation Team.

Attachment 18 contains additional requirements which include:

- Provide input to the soliciting utility on:
    - The development of screening and evaluation criteria, ranking factors and evaluation methodologies that are reasonably designed to ensure that the solicitation process is fair, reasonable and in the public interest in preparing a solicitation and in evaluating bids;

    - The development of initial screening and evaluation criteria that take into consideration the assumptions included in the soliciting utility's most recent IRP, any recently filed IRP update, any Commission Order on the IRP or IRP update and its Benchmark option;

- Whether a bidder has met the criteria specified in any RFQ and whether to reject or accept non-conforming RFQ responses;

- Whether and when data and information should be distributed to bidders because it is necessary to facilitate a fair and reasonable competitive bidding process or has been reasonably requested by bidders;

- Whether to reject non-conforming bids or accept conforming changes.

- Upon advance notice to the soliciting utility, the IE may conduct meetings with intervenors during the solicitation process to the extent determined by the IE or as directed by the Commission.
- If at any time the IE becomes aware of any violation of any requirements of the solicitation process or Commission rules, the IE shall immediately notify the soliciting utility and the Commission. The IE shall report any actions taken by the soliciting utility and any other recommended remedies to the Commission.
- The IE shall document all substantive correspondence and communications with the soliciting utility and bidders, shall make such documentation available to parties in any relevant proceedings upon proper request and subject to the terms of a protective order if the request contains or pertains to confidential information.