Attachment 1

PacifiCorp RFP Issues

The following are my initial thoughts on several issues discussed during the bidders and stakeholders conferences with regard to the 2012 PacifiCorp RFP as well as during our meeting after the first bidders' conference.

1. **Capacity requirements and timing**

Several of the stakeholders raised issues regarding the level and timing of capacity requirements and the options to consider for soliciting proposals through the bidding process. In fact, there appeared to be multiple positions of the parties with regard to the timing for capacity, the type of capacity to solicit for, the role of the "bridging resources" and the appropriate benchmark or comparison resources.

In its presentation, PacifiCorp expressed a preference to solicit for capacity requirements for 2012 and 2013. The company indicated that the proposals submitted would be evaluated relative to the two benchmark resources identified (i.e. Hunter and Bridger, both supercritical pulverized coal options), the alternative portfolios identified (i.e. bridging resources, which included the West Valley Project, Gadsby Repower and IPP 3) and the company's forward curve as a representative of the short-term market price. PacifiCorp's approach was based on a strategy of securing long-term reliable resources to meet customer requirements. PacifiCorp felt it was not reasonable to solicit for shorter-term resources in this RFP process since the long lead time between the initiation of the RFP and date the power is needed would be several years and would not be feasible for short-term options bid into this RFP.

During the Friday, June 2 stakeholders' conference a number of comments were raised about the proposed resources which would be solicited and the methodology/approach for evaluating and selecting a resource portfolio.

The Oregon Commission staff was concerned that IGCC options will not be considered unless PacifiCorp included an IGCC option as a benchmark or the 2014 need is included in the RFP process. The Oregon staff also mentioned that the so-called "bridge" resources should also be subject to competitive bidding. The UAE and others advocated a flexible process whereby both long-term and short-term options would be allowed to compete. They advocated a more diverse portfolio that would not be based solely on long-term firm options but would provide PacifiCorp the opportunity to continually assess new technologies by having a portion of the portfolio terminate each year.

The challenge appears to be "can PacifiCorp's resource needs and objectives for securing long-term reliable resources be balanced against the concerns of other stakeholders to assess new technologies such as IGCC or changes in technology/resource options"?

The issues of the timing and requirements for resources in light of uncertain load growth, changes in technology, environmental requirements and costs (i.e. CO2 and mercury impacts), market prices and resource availability and other factors are exacerbated by the trend toward long lead-time coal-based resources. To address such uncertainty, in other RFPs utilities have requested bidders to propose options for hedging the above risks. These included in-service date acceleration options, in-service date deferral options, and contract buyout options as a component of the bidding process. In several RFPs (e.g. Hydro-Quebec, Southwestern Electric Power Company, Public Service of Oklahoma, and Central & SouthWest), Bidders were requested to propose a price schedule (or price proposal) at which the utility could exercise the above options. Under this concept, the bidder may offer a price for deferral, contract buyout, and/or acceleration at various points on the project milestone schedule. Such options provide the buyer the opportunity to assess the direction of the market and make a decision closer to the time the utility actually needs the power.

For example, assume a utility conducts a competitive bidding process and selects a supercritical pulverized coal option for an in-service date of June 2012. Prior to the time the project sponsor seeks financing (i.e. 12-18 months after contract signing or over two years after the RFP is issued), it becomes known that IGCC options are becoming more economic, environmental requirements are becoming more stringent or more information is known about CO2 controls that makes this IGCC option more feasible. The utility could either decide to maintain the original contract, defer the in-service date and buy short-term power if it is more economic to do so or buyout the original contract and either build the IGCC unit or purchase the power from someone else (i.e a third-party IGCC unit). An additional option which might be negotiated with bidders could be the terms controlling the Change Order to the original contract (schedule and cost impact) that would be triggered if the utility exercises an option to order the substitution of a supercritical pulverized coal project to an IGCC. The economic decision involves a delay in committing to a specific option to secure more market information and an assessment of all costs (including the difference between market prices for each option), as well as the value of the options to buyout or defer the in-service date.

The following is an example of how options could be effectively included in the evaluation process to allow for consideration of the issues raised by stakeholders, notably the ability to “buy more time” to consider the viability of an IGCC resource option. As noted above, assume that PacifiCorp issues its RFP for baseload resources as scheduled. PacifiCorp continues to study the IGCC option for 2014. The final RFP is issued in October 2006. The process takes 8 months to arrive at a decision regarding the preferred resource. Assume PacifiCorp selects a supercritical pulverized coal project with an in-service date of June 1, 2012. The bidder submits a pricing schedule for buyout of the contract at different milestone dates (i.e. upon contract execution; one year after contract signing to conform to the date for securing permits; prior to securing financing). Upon selection of the proposal, PacifiCorp completes the contract with the proposed buyout options included. One year after signing the contract (and nearly 2 years since initiating the RFP process), PacifiCorp’s continued research and market intelligence indicates that IGCC options are favored from an economic and environmental perspective. Assume the project developer had estimated that it would have sunk $5 million in development costs in the project and bids this amount as its buyout price. If the cost of the contract buyout plus the IGCC project costs are more favorable to customers than the supercritical pulverized coal option, it is preferable to buy out the contract and secure a deal with the IGCC option. The application of option pricing concepts has provided PacifiCorp with the opportunity to further assess the market and costs of the IGCC option while buying time to allow the technology to mature. Such an approach may meet the concerns of the Oregon Commission staff, while allowing the RFP to move forward to secure needed resources in a timely fashion.

In cases with such planning uncertainty, such provisions as flexibility options are important tools to manage risk and select the best options. However, such options require more complex analysis and continued management of the contracts. While option pricing models have been used for such analysis, the decisions are complex and time consuming. However, as others have done, it may be feasible to model the options by assuming the option would be exercised and assessing the cost of the portfolio with the various options considered in the detailed portfolio evaluation process. This was essentially the approach taken by Hydro-Quebec in the assessment of the value of such options submitted in their first Call for Tenders process. We could work with the Division, Commission staff and the Company to identify approaches for assessing such option values.

Select sections from other RFPs that have solicited for such options are available. We could provide those sections from the RFPs upon request.

2. Lessons Learned from Coal Based RFPs

Coal-based RFPs are becoming more common as gas prices have increased and coal projects have become more economic for baseload applications. However, the implementation of an effective competitive bidding process for baseload coal resources is subject to several challenges:

- Unlike gas-fired combined cycle options, coal technologies are not based on standard design. Thus, the costs and operating parameters will vary for each project. Coal project design is based on the type and quality of coal available and other factors that lead to a unique project design. As a result, it is difficult for project sponsors to quote a fixed price and manage the cost risk relative to their bid pricing.

- The lead-time for coal-based resources is nearly twice as long as for gas-fired combined cycle projects. This creates additional cost and market uncertainty. The longer the lead time to commercial operations the greater the potential risk exposure and the higher the potential cost premium. As a result, the longer lead-times create additional cost risk for project sponsors.

- Also, at the current time the demand for Engineering, Procurement and Construction (EPC) services, shortages of skilled labor, and competition for resources such as steel and other materials is pushing up such costs and is creating additional cost uncertainty.

In other competitive bidding processes, both the utility and independent developers have raised concern over such cost exposure. From the utility perspective, the concern is the risk of cost disallowance if costs are ultimately much higher than anticipated. For the IPP, the concern is the traditional requirement in the RFP that the bidder "fix" its price or lock-in its capacity payment at the time of bid submission. Since the IPP will be paid on the basis of the bid price, the cost of uncertainty is generally built into the bid price, thereby increasing the price bid and cost to the consumer. This situation potentially makes it more difficult for the IPP to compete effectively against a utility coal option or be in a position to increase its price to compensate for the risk.

Furthermore, while the third-party bidder may be required to lock-in its capacity price years in advance of either executing an EPC contract and/or reaching commercial operations, utility projects are subject to cost-of-service regulations. If the utility is able to justify any cost increases above its bid or benchmark costs as "out of its' control", such costs are generally recoverable. On the other hand, while third-party bidders do not face a limited return as the utility does, the third-party is subject to a potentially higher return but potentially higher costs and lower return as well. With such capital intensive projects as coal-based options, the risk of higher costs in such an uncertain environment may discourage third-party proposals, create disincentives to bid, and lead to limited competition.

A recent RFP issued by Public Service Company of Oklahoma (PSO) attempted to address some of these issues by allowing third-party and self-build options to index components of their capacity price to market indices such as inflation, steel prices, etc. either until the in-service date or execution of the EPC agreement. At that point the capacity price would be fixed for the term of the contract or would be allowed to escalate by a fixed amount (e.g. 2% per year). The basis of this option is to allow a major component of the bid price (i.e. the capacity component) to adjust to the market until either the EPC agreement is executed or the project enters service. Bidders would then be able to more closely match the EPC costs to their bid prices without being subject to market vagaries for several years and would thus face less price risk. Such an approach potentially shifts risk to the buyer from the seller but could lead to lower prices and more competition between the utility and the IPP.

Without such a pricing option, the IPP would have difficulty competing against the utility self-build or benchmark option and bids from third-parties may be discouraged if there is not a "level playing field". Such an approach effectively places the utility self-build and a third-party bid on a more equal footing.

Another off-shoot to this approach is to allow bidders and the utility to submit two pricing options: (1) a base price and (2) a price with contingencies that provides the bidder with a 95% probability of meeting or beating the contingent price. Bid evaluation is initially based on the price with contingency but the final selection could be based on price negotiation below the contingency as the third-party bidder and utility are able to further develop their project subsequent to selection for the short-list.

Finally, in a competitive bidding process, more standardized options such as combined cycles and combustion turbines will have a favorable price advantage relative to baseload coal options since coal options will have to include a risk premium in their bid price relative to more standard products with shorter lead times.

3. Credit Requirements

One of the most contentious issues in competitive bidding processes today is the level and form of credit requirements for third-party bidders. In general, the level of security required from successful bidders has been increasing. In addition, several recent RFP processes have required that a bidder or its credit support provider has to have an investment grade credit rating to participate in the bidding process. In some cases, bidders with below credit ratings have been allowed to compete but such bidders have had to post a significant amount of security and/or maintain a high net worth threshold.

As with the second issue above, utility self-build projects could enjoy a significant competitive advantage relative to third-party bidders if the credit requirements imposed on third-parties is too onerous. As background, the credit problems faced by third-party generation companies has raised concern on the part of the purchasing utility that the probability of contract default and the associated costs to customers to replace the power under the contract could be significant. Low credit quality counterparties could pose a significant risk of default for a third-party project if such an entity has difficulty raising the capital to complete its project. In such a case, the type of security becomes important since the utility needs access to the security or credit to pay for the power it has to secure to replace the contract power. The level and type of credit or security requirements thus has become a significant issue in RFP processes.

Utilities argue that they require ready access to the security to compensate the utility for purchasing replacement capacity and/or energy. Third-parties will argue that the level and type of security could take several forms, particularly if a physical asset is supporting the contract and the utility, after construction starts, can treat the independent physical asset in the same way, from a credit point of view, as it treats its self-build option. In this latter regard utilities plan to take over and complete any self-build option if their EPC contractor defaults. Third-parties argue that second liens, step-in rights, or power plant insurance policies should be a component of the security required and can effectively place the utility in the same position as it would be if its EPC contractor defaulted during construction. Utilities argue that such forms of security as step-in rights or second liens are not very liquid and it may take years to resolve the allocation of the credit required by the utility. Since letters of credit, cash or a corporate guarantee are more liquid and accessible, utilities prefer these forms of security. Independent project sponsors counter-argue that liquid credit requirements for independent power projects need not exceed the same liquid requirements for EPC contractors, or in the worst case, should not exceed the coverage required to pay the excess costs, if any, of replacement power for the short period of years until a replacement power project can be brought on line by the utility.

It is interesting to note that since the power trading scandals and issues of the early 2000's, the credit departments of utilities have generally been more stringent with such credit requirements. The credit departments of utilities have actually been implementing the credit policies applied to power trading arrangements to RFP processes for physical assets. The difference between the credit requirements for power trading arrangements and contracts backed by physical assets is an emerging and controversial issue in RFP processes.

In addition, power generators have traditionally established special interest entities as vehicles to maintain the specific power project contracted with the utility. As such, these entities have no other assets or sufficient net worth. Furthermore, such projects do not have specific credit ratings. To meet traditional credit requirements, these entities will either have to secure the necessary credit or rely on a guarantor with an adequate credit rating. Since the cost of providing a letter or credit or corporate guarantee can be significant, power project sponsors have raised the concern that such entities are not consistent with the level and type of security required by utilities. As a result, they have proposed security in the form of a second lien or step-in rights as a complement to a letter of credit or corporate guarantee. Some utilities maintain that a parent guarantor needs to support the power project rather than allow the special interest entity to effectively develop and finance the project and contract the power to the utility based on the strength of the utility's balance sheet. Independent producers claim in response that the self-build option is supported exactly in the same fashion --- on the strength of the utility balance sheet --- and since ratepayers are responsible for providing that strength, it must be shared as an element of fundamental fairness in the bidding process.

As illustrated in the attached matrix, the approach taken by utilities with regard to credit or security requirements in other RFPs has taken a number of forms. At the current time there is no "industry standard" in this regard. For example, some utilities have restricted participation in the RFP to only participants that have an investment grade rating or have a corporate guarantor with an investment grade rating. Others allow all entities to participate but have established a high net worth threshold to compete. Still others state they will negotiate the level of credit required at the time the contract is negotiated.

The conflict in the positions of the utility and the third-party project sponsor is becoming an issue in a number of bidding processes. In some recent RFPs, potential bidders have argued that credit provisions are too onerous. This could either discourage project sponsors from bidding or potentially face the possibility of rejection for non-conformance after submission of their proposal. It is anticipated that credit issues will become more significant as third-party project developers become more active in competitive bidding processes.

4. Type of Bidding Process

For a coal-based RFP, the type of bidding process implemented could have important ramifications for the success of the process. PacifiCorp has proposed a process based on several stages including: (1) pre-qualification of bidders; (2) selection of a short-list based on price and non-price factors; (3) detailed portfolio evaluation; and (4) contract negotiations. Based on recent experiences with other forms of bidding processes, we believe that this approach is applicable to a coal-based RFP since coal projects are unique in design and operations. This contrasts with the more standard design for combined cycle, combustion turbines and even some renewable technologies.

Utilities have generally implemented one of four bidding processes including (1) Multi-stage evaluation process; (2) Pre-qualification process; (3) Indicative bidding process; and (4) Competitive negotiations. As will be discussed below, while the Multi-stage evaluation process has been the most common, this process may not be the best for implementing a coal-based RFP.

The Multi-stage process requires all eligible bidders to submit complete proposals. Proposals are then subject to a threshold evaluation. Bids which meet the threshold criteria are subject to a price and non-price evaluation. The best bids within each category are then placed on a short-list for a detailed evaluation based primarily on a price or cost assessment. The best bid(s) or portfolio of bids is then subject to contract negotiations. The problem with this process is that all bidders have to spend significant dollars and time to prepare their bids but may actually be eliminated at the threshold stage. Thus, bidders may be discouraged from participating if there is a significant risk that they will be deemed in non-conformance with the RFP requirements.

The Pre-Qualification process effectively replaces the threshold stage after receipt of bids with a pre-qualification process prior to submission of a final detailed bid. Bidders have to provide financial information, a summary of their development experience, a description of the technology, etc. but do not have to submit a detailed proposal at this stage. Only bidders that are pre-qualified are eligible to submit a detailed proposal. While this process may take a bit longer to complete than the multi-stage process, bidders will not have to spend significant time and money up-front to submit a bid. Bidders will know before expenditure of significant dollars if they are eligible. Since the costs of preparing a coal-based proposal can be significant, bidders prefer to have assurance that they meet the minimum requirements before submitting a detailed bid. Such a process should therefore lead to more competition and better bids overall. Based on past experience, such a process is more consistent with coal-based projects than any other form of RFP process.

The Indicative Bid process contains significant redundancy in its requirements through the requirement for an initial indicative bid followed by a binding bid. Such a process is not well designed for RFP processes where new Greenfield assets are a primary component of the process.

The final type of bidding process is competitive negotiations. While competitive negotiations has a number of merits in allowing the utility to keep improving the final contract through negotiations with several projects, the process is time consuming and detailed. We classified PacifiCorp's 2003 RFP process as an example of a competitive negotiations process. Some elements of this process, particularly at the contract negotiations stage may be valuable to improve the final product.