- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PacifiCorp for Approval of a 2009 Request for Proposals for Flexible Resource	))))))	DOCKET NO. 05-035-47 COMMISSION'S SUGGESTED MODIFICATIONS

ISSUED: December 21, 2006

SHORT TITLE

PacifiCorp 2012 RFP Suggested Modifications

SYNOPSIS

The Commission suggests modifications to PacifiCorp's Draft 2012 Request for Proposals for Base Load Resources.

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APPEARANCES:

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Paul Proctor Assistant Attorney General	"	Committee of Consumer Services
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I. PROCEDURAL HISTORY

On June 27, 2005, pursuant to Utah Code Annotated §§54-17-101, et. seq., Energy Resource Procurement Act ("Act") and in accordance with Utah Code Annotated §54-17-201(2)(b), PacifiCorp ("Company"), filed an application to the Public Service Commission of Utah ("Commission") for approval of its 2009 Request for Proposals for a Flexible Resource ("2009 RFP"). On July 20, 2005, the Commission issued a Scheduling Order setting the schedule for this docket.

In accordance with the Scheduling Order, on August 22, 2005, comments on the 2009 RFP were filed by the Utah Division of Public Utilities ("Division") the Utah Committee of Consumer Services ("Committee"), Western Resource Advocates ("WRA"), and Utah Association of Energy Users ("UAE"). On August 22, 2005, the Northwest Independent Power Producers Coalition requested an extension of time to file comments on the 2009 RFP and subsequently filed its comments on August 30, 2005.

On September 2, 2005, the Company filed a Motion to Extend Procedural Schedule for the 2009 RFP by approximately 30 days in order to provide additional time for the Independent Evaluator ("IE"), Merrimack Energy Group, Inc., to provide substantive comments to new information posted by PacifiCorp on August 31, 2005, and to ascertain what impact, if any, there would be to the amount and/or timing of the 2009 resource need based upon the Company's recent review of the resource assumptions contained within its 2004 Integrated Resource Plan ("2004 IRP") filed in Docket No. 05-2035-01. In response to this request, on September 12, 2005, the Commission issued a Revised Scheduling Order for this case.

On September 16, 2005, the IE filed its "Report of the Independent Evaluator Regarding PacifiCorp's 2009 Request for Proposals For Flexible Resources."

As a result of the Company's review and update of the resource assumptions contained within the 2004 IRP, on October 19, 2005, the Company filed a Motion to Suspend Procedural Schedule for the 2009 RFP. In this motion the Company requested the current proceedings be suspended pending the results of the updated 2004 IRP. In response to this request, on October 21, 2005, the Commission issued a Notice of Suspended Schedule and Notice of Scheduling Conference, which was subsequently amended on November 4, 2005. Also on November 4, 2005, PacifiCorp filed in Docket No. 05-2035-01, an update report to its Integrated Resource Plan 2004. The update is entitled "2004 Integrated Resource Plan Update" ("2004 IRP Update") and includes a significantly revised action plan. Following a scheduling conference, on January 30, 2006, the Commission issued a Revised Scheduling Order for review of the 2009 RFP.

On April 19, 2006, following the March 21, 2006, closing of the MidAmerican Energy Holdings Company ("MEHC") acquisition of PacifiCorp, the Company submitted a Motion to Extend the Procedural Schedule in order for the Company and MEHC to have adequate time to review and discuss in greater detail the technical, financial and regulatory issues associated with PacifiCorp's resource planning and acquisition process. In response to this request, on May 4, 2006, the Commission issued a Revised Scheduling Order. Technical conferences were held pursuant to notice on March 6, 2006, April 3, 2006, May 9, 2006 and September 21, 2006.

On July 11, 2006, the Company filed its Draft 2012 Request for Proposals Base Load Resources ("Draft 2012 RFP") and associated Appendices for up to four base load resources in the east control area commencing in the year 2012.

On August 16, 2006, comments on the Draft 2012 RFP were filed by the Division, the Committee, WRA, UAE, and LS Power Associates, L.P. ("LS Power"). On August 30, 2006, the IE submitted the Report of the Independent Evaluator on PacifiCorp's Draft 2012 RFP. On September 14, 2006, the Company filed reply comments.

At the request of the parties, the Commission issued an Amended Scheduling Order on August 22, 2006, changing the dates of the hearing on the Draft 2012 RFP to October 3, 4, and 5, 2006. On September 26, 2006, the Commission issued an updated scheduling order setting, among other things, the date for the RFP hearing, if required, for November 3, 2006.

On October 4, 2006, the Company filed its Revised Draft 2012 RFP in response to the comments filed on August 16, 2006. On October 13, 2006, the Company filed a Motion for a Protective Order, and the Commission issued a Protective Order.

On October 13, 2006, comments on the Revised Draft 2012 RFP were filed by AES Corporation, the Utah Chapter of the Sierra Club ("Sierra Club"), the Division, the Committee, WRA, UAE, LS Power, the IE and numerous members of the general public.

In preparation for the hearing, witness lists were filed with the Commission by the Company, the Division, the Committee, and LS Power on November 1, 2006, and by WRA on November 2, 2006. In addition, on November 1, 2006, the Division submitted a Joint Position Matrix summarizing the positions of the parties on unresolved and resolved issues associated with the Revised Draft 2012 RFP, and UAE submitted its position statement on the Company's Revised Draft 2012 RFP.

On November 2, 2006, the Company filed a second Revised Draft 2012 RFP, requesting up to two, rather than four, base load resources, to which the Division filed comments and the Committee filed a request to file post-hearing briefs which was granted by the Commission at hearing on November 3, 2006.

A hearing on the second Revised Draft 2012 RFP was conducted on November 3, 2006. On November 13, 2006, post-hearing briefs were filed by the Company, the Division, the Committee, and WRA.

II. DISCUSSION, FINDINGS AND CONCLUSIONS

A. INTRODUCTION

On February 25, 2005, the Utah Legislature enacted the Energy Resource Procurement Act ("Act"), Utah Code Annotated §§54-17-101, et. seq. This Act requires any PacifiCorp significant energy resource ("SER") acquisition of 100 megawatts ("MW") or greater for 10 years duration or longer to be competitively bid unless a waiver is granted. In the absence of a waiver, the Act requires the Company to conduct a solicitation process that is approved by the Commission.

The Act requires the Commission to appoint an independent evaluator to actively monitor the solicitation process for fairness and render an opinion as to whether the solicitation process is fair and in compliance with the Act, and whether any modeling used by the affected electrical utility to evaluate bids is sufficient. The Act also requires PacifiCorp obtain

Commission approval of its SER decision prior to construction or entering into a binding agreement.

On January 20, 2005, the Company completed and filed its 2004 IRP which provides the Company's least cost portfolio of resources, its "Preferred Portfolio," needed to meet future expected demand for electricity, given the Company's assumptions regarding future resource costs, risks and uncertainties. The 2004 IRP identifies the need to procure 550 MW of a flexible natural gas-fired resource in or delivered to Utah by the summer of 2009. The need for the flexible natural gas-fired resource formed the basis of the Company's 2009 RFP filed in this docket. The 2004 IRP also identifies the need to procure 600 MW of a high capacity factor coal resource in or delivered to Utah by the summer of 2011 and selects 383 MW of a coal resource in Wyoming in 2014.

Subsequently, the Company filed its 2004 IRP Update. In its 2004 IRP Update, PacifiCorp states the gap between loads and resources identified in its 2004 IRP is diminishing. The change is primarily due to updates in resource assumptions that cause the delay or elimination of online dates for resources identified in the 2004 IRP Preferred Portfolio. One notable change is the elimination of the need for the 2009 flexible gas-fired resource. Specifically, the 2004 IRP Update includes newly executed power purchase contracts, a change in assumption regarding the extension of qualifying facility and interruptible contracts, extension in a thermal plant life, a reduced assessment of existing hydroelectric resource generation, an additional demand side management program, additional existing renewable resources, changes to front office transaction modeling (in other words, planned market purchases) and topology changes. The net effect of these changes is a decrease in resource deficit relative to that projected in the 2004 IRP. Consequently, PacifiCorp states the Preferred Portfolio identified in the 2004 IRP is no longer optimal from resource quantity or timing perspectives.[1]

In its 2004 IRP Update, the Company evaluates least cost-least risk approaches to meeting the newly identified load and resource balance and develops its "2004 IRP Update Preferred Portfolio." This portfolio identifies the need for a 575 MW coal resource in Utah in 2012, a 561 MW natural gas resource in Oregon in 2012 and a 500 MW coal resource in Wyoming in 2014. The 2004 IRP Update states the amount of need in 2012 is about 600 MW. Accordingly, the Company revised its IRP Action Plan to procure a 600 MW resource capable of making deliveries in Utah in 2012 and named a conventional coal plant as its IRP proxy for this resource. The Company also states it would need to award an engineering and construction contract in 2007 in order to address the long lead time necessary to construct the coal resource.

Based on the changes in the 2004 IRP Update, the Company requested suspension of this docket and replaced the RFP for the 2009 flexible natural gas resource with an RFP for 2012 base load resources. ("2012 RFP").

The Company's July Draft 2012 RFP and October Revised Draft 2012 RFP solicit base load resource bids to fulfill a portion of the supply-side resource need identified in the Company's 2004 IRP and 2004 IRP Update. The July Draft 2012 RFP was revised in October to provide greater clarity and to address comments made by parties on the July Draft 2012 RFP. Both drafts solicit bids for 1,600 MW to 2,290 MW between 2012 and 2014, and identify four benchmark resources against which bids will be compared. This solicitation is based on

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[1] 2004 IRP Update, page 21.

Company analysis of resource deficit in the eastern part of its system identified in its 2004 IRP, 2004 IRP Update, and 2006 IRP work-to-date ("2006 IRP"), which the Company states is between 1,640 MW (2006 IRP) and 2,743 MW (2004 IRP) by 2012. Base load resource bids must be capable of delivering energy and capacity in or to the Company's eastern control area transmission system and fulfill the requirements as a network resource. Base load resource bids may be any fuel type, and must provide unit contingent or firm capacity and associated energy and be available for dispatch or scheduling by June 1, 2012, June 1, 2013, and/or June 1, 2014, respectively. The Company may opt to contract for more or less power depending on the quality of bids, changes to Company forecasts, regional transmission availability and timing, and wholesale energy market conditions. The Company benchmarks are 600 MW of a coal resource at the Hunter Power Plant site in 2012, 340 MW of a coal resource at the Intermountain Power Plant ("IPP") site in 2012, 750 MW of a coal resource at the Jim Bridger Power Plant site in 2013 and between 250 MW and 600 MW of an Integrated Gasification Combined Cycle ("IGCC") resource in 2014.

The Company again revised the Draft 2012 RFP in November 2006. This November Draft 2012 RFP solicits bids to fulfill a portion of the supply-side resource need identified in the Company's 2004 IRP and makes no mention of the 2004 IRP Update resource needs or 2006 IRP work-to-date. The November Draft 2012 RFP solicits bids for 840 MW to 915 MW between 2012 and 2013, and identifies two benchmark resources (with one alternate) against which bids will be compared. The Company bases this solicitation on its analysis of resource deficit in the eastern part of its system in the 2004 IRP, but assuming a 12 percent planning margin, and states this deficit is between 808 MW and 1,109 MW by 2013. The definition of a base load resource remains the same but bids must be available for dispatch or scheduling by June 1, 2012, and/or June 1, 2013, respectively.

At hearing, several outstanding issues were raised for Commission consideration and determination as to whether the Commission will approve, suggest modifications to, or reject, the November Draft 2012 RFP, as required by Utah Code §54-17-201(2)(f). These issues are: 1) Resource need, type and timing; 2) independent evaluator liability waiver; 3) comparability and price indexing; 4) credit requirements; 5) modeling and allocation of carbon dioxide (“CO2") risk; and, 6) innovative bid proposals. We address each issue in turn.

B. RESOURCE NEED, TYPE, AND TIMING

In the Company’s November revision of the Draft 2012 RFP, the Company significantly changes the amount of resources requested through the solicitation, and the amount of its benchmark resources, from prior drafts. These amounts are disputed. We first describe each party’s position.

The Company testifies it has not reduced its need for resources with the filing of its November 2, 2006, Draft 2012 RFP. Rather, it reduced the level of benchmark resources and shortened the term from three years (2012 -2014) to two years (2012-2013) in order to accomplish several objectives. First, it believes it can reasonably build this level of benchmark resource. Second, it states it is very concerned about the amount of time it is taking to complete the process and believes reducing the planning margin to 12 percent will help obtain concurrence across states so the Company can move forward. The Company states it will need to issue additional RFPs or amend this one once it gets through the process. Further, it states the lower level of benchmark resource does not preclude the Company from procuring additional megawatts to the extent it gets proposals that are cost effective for customers and which address risk and reliability on a portfolio basis.

The Company also asserts it reduced the term of the RFP by one year in order to respond to stakeholder concerns about the magnitude of the resources procured through one RFP and in order to make the process more manageable for the Company, stakeholders, and customers. Additionally, the Company will await the results of the 2006 IRP and in turn will implement the plan derived from that preferred portfolio.

The Company testifies its November Draft 2012 RFP is based on a need of 1,100 MW in 2013 on the east side of its system. It determined this level of need by employing all 2004 IRP assumptions, except for its use of a 12 percent planning margin instead of the 15 percent planning margin used in the 2004 IRP. This 1,100 MW is in addition to 700 MW of market purchases it will also need to acquire.

The Division testifies the November Draft 2012 RFP falls short of meeting the criteria set forth in Utah statute and the IRP. The Division argues the November Draft 2012 RFP solicits insufficient resources to meet the Company's identified resource needs during the RFP time frame. The Division states the 12 percent planning margin the Company uses to identify resource need is not analytically based and may result in an undesirable level of reliability. The Division states both the 2004 IRP and 2004 IRP Update based the choice of a 15 percent planning margin on the findings of a loss of load probability ("LOLP") study completed for the 2004 IRP. This study found that while an 18 percent planning margin would be necessary to reach the desirable result of a 1 in 10 LOLP, a 15 percent planning margin would still equate to a 2 in 10 LOLP, which the Division considers to be an acceptable level of reliability. The

Division states it does not know what level of reliability a 12 percent planning margin equates to and therefore the Division cannot state the proposed solicitation takes reliability into consideration as required by the Act.

The Division states the timing and size of the resources being sought appear to be inconsistent with the 2004 IRP and 2004 IRP Update, with the projected needs on the Utah side of PacifiCorp's system, and with the public interest as defined by Utah law. The Division states even when planned market purchases are excluded from the projected deficit, the proposed changes in the size and timing of the benchmarks appear inadequate to meet resource needs in 2012 and 2013. The Division calculates that acquiring the benchmarks identified in the November Draft 2012 RFP results in a Utah area deficit of 349 MW in 2012 and 160 MW in 2013, a deficit that is over and above the additional 700 MW of deficit planned now to be filled through market purchases rather than physical assets. This is in contrast to the July and October Draft 2012 RFPs which provided physical assets to meet the market purchases need.

The Division counters the Company's contention that it can not now build the benchmarks it initially proposed by observing that on two occasions when the Company requested delays in this docket, the Division itself had expressed its concern that delay could jeopardize the timing of resources. The Division is concerned further delay will occur now that the Company has shortened the RFP time frame from three years through 2014 to only two years through 2013. With these changes, the Company and bidders may have inadequate time to bring longer lead time but less expensive resources online, leaving Utah ratepayers exposed to the vagaries and volatility of the market either through market purchases or gas-fired generation. Therefore, the Division recommends the Commission condition its approval of the RFP on acceptance of certain language changes. The first includes a statement that the Company intends to contract for power up to the east side resource deficit amounts reflected in its 2004 IRP Update, including the 700 MW of deficit planned to be filled through market purchases, which is approximately 1,700 MW by 2013 and 2,000 MW by 2014. The second includes requiring the Company to fully consider bids in 2014 or requiring it to file a new RFP for 2014 no later than December 31, 2007.

The Committee concurs with the Division regarding resource need and also questions the reasonableness of the 12 percent planning margin. The Committee provides data on east side resource deficit in the 2004 IRP, 2004 IRP Update, and 2006 IRP, with and without planned market purchases, and compares this deficit to benchmark resources in both the October and November Draft 2012 RFPs. The 2006 IRP deficit is based on the Company's most current forecasts regarding fuel and market prices and loads. The Committee shows this east side resource deficit is smaller than the east side resource deficit in the 2004 IRP Update but remains in excess of the Company's November Draft 2012 RFP benchmarks by 123 MW to 823 MW in 2012, 146 MW to 846 MW in 2013 and 835 MW to 1,535 MW in 2014, with planned market purchases excluded and included in the deficits, respectively.

The Committee states the risk of reliance on significant market purchases to meet capacity deficits was inadequately addressed in the 2004 IRP and 2004 IRP Update. The Committee testifies significant reliance on the market for capacity is especially risky because the surplus in the West is disappearing. Except for the surplus in the Pacific Northwest, the rest of the West will be deficit in the 2008 to 2009 time period. The Committee concurs with the Division that language should be added to the RFP to ensure it will acquire firm resources with stable prices for power as soon as possible which will reduce market and gas price risks. Additionally, the Committee recommends the Commission approve the solicitation process subject to and conditioned on eight recommendations the Committee makes in its post-hearing brief. The recommendations primarily relate to multi-state activities and on-going IRP analysis.

UAE is supportive of the magnitude of benchmarks proposed by the Company in its November Draft 2012 RFP because the Company should not be expected to add more benchmarks than it can realistically complete. In comments to the Commission on the 2004 IRP and 2004 IRP Update, UAE supports a 12 percent planning margin and expresses concern that the magnitude of resource need identified by the Company in its 2004 IRP and 2004 IRP Update is too high. Nonetheless, UAE supports the base load coal resources identified as least cost and shares the Division's concerns about delaying the process to the point only suboptimal plants can be acquired. UAE urges Utah to move forward on the RFP and suggests the RFP should be clear that more than just the minimum amounts of resource can be considered if such resources are economical and meet a perceived need.

While WRA and the Sierra Club do not directly contest the resource need, they disagree with the type of benchmark resources the Company selected to fill the need. WRA disagrees IPP Unit 3 or Hunter Unit 4 meet the public interest standard under the Energy Resource Procurement Act because of the long-run CO2 impacts they impose. Rather, WRA recommends short-term transactions, demand-side management, renewable energy resources and qualifying facilities be acquired to allow deferral of major capital expenditures, to gain greater clarity on future climate change regulations and to delay decisions until such time as IGCC technology and other technologies better suited for addressing CO2 emissions can be deployed.

Thus, WRA recommends the RFP should only include one benchmark, the Company's 2013 IGCC benchmark option at the Jim Bridger Power Plant. WRA comes to this conclusion because its view of the likely cost associated with meeting future climate change policy is much higher than the Company's $8 per ton assessment. WRA understands parties' concerns about short-term transactions and the market risk they present. However, WRA believes it would be imprudent to manage this short-term market risk through the development of potentially much riskier 40 to 50 year investments in high CO_2 emitting technology with limited flexibility for addressing CO_2 over the long term. WRA questions the credibility of the IPP 3 2012 in-service date due to development risks and multi-state approval risks. WRA also questions whether base load resources are the appropriate benchmarks to meet an essentially growing peak demand during a limited number of hours and questions the Company's assumptions regarding off-system sales of surplus energy from pulverized coal units because of changes in California laws.

In ruling on the request for approval of a solicitation process, the Act requires the Commission determine whether the solicitation process is in the public interest taking into consideration: 1) whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to Utah retail customers; 2) long-term and short-term impacts; 3) risk; 4) reliability; 5) financial impacts on the affected electrical utility; and, 6) other factors determined by the Commission to be relevant.

Our IRP standards and guidelines for PacifiCorp require an analytical process for evaluating alternative resource portfolio costs that we believe is consistent with the Act's public interest considerations.[2] It is the Company's IRP process that provides an analysis of generating resources, demand side management and transmission alternatives to meet expected demand, and evaluates alternatives under a range of assumptions regarding future market prices, loads, forced outage rates, hydro conditions, environmental costs and stochastic variability to determine a least cost, least risk portfolio. In order to conclude the RFP is "most likely" to result in electricity at the lowest reasonable cost for Utah customers, we examine the record to determine that the amount, type and timing of the Company's November Draft 2012 RFP and benchmarks are consistent with its least cost and risk analysis.

All parties addressing the issue agree the November Draft 2012 RFP does not seek an amount of resource in 2012, 2013 or 2014 adequate to meets its projected resource deficit, no matter which iteration of IRP analysis is assumed. Even in comparison to the Company's 2004 IRP assessment of deficit using the unsupported, and possibly unreliable, 12 percent planning margin, this RFP falls short. The greater question for us is whether it is necessary for the Company to issue an RFP that requests an amount of resource equal to its entire expected deficit or whether it is acceptable for it to seek an amount of resource consistent with a subset of planned resource additions, i.e., base load supply side generation, in a given

[2] "The Commission will require PacifiCorp to pursue the least cost alternative for the provision of energy services to its present and future ratepayers that is consistent with safe and reliable service, the fiscal requirements of a financially healthy utility, and the long-run public interest." Docket No. 90-2035-01, page 1. The Order defines IRP as follows: "Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty."

time frame. This leads us to an examination and decision regarding the reasonableness of the Company's choice of base load coal resources as the RFP benchmark resources against which bids will be compared.

The Company, Division, Committee and UAE support super critical coal and IGCC resources as the Company's benchmark resources. WRA and the Sierra Club do not support the super critical coal, base load resources and argue this deficit should be filled with short-term transactions, demand side and wind resources, and cogeneration. Although WRA opposes the super critical coal resource benchmarks, it does not provide specific alternative benchmark costs and characteristics with which to replace the Company's benchmarks. One primary recommendation made by Navigant, the Company's outside consultant in the last bidding case, was to require Company-owned or controlled benchmark resources in the RFP in order to evaluate the reasonableness of bids and ensure least cost electricity to customers.

In both its 2004 IRP and 2004 IRP Update, the Company identifies base load, super critical coal resources as part of its preferred portfolio, 958 MW in the former and 1,075 MW in the latter, respectively, taking into account cost and risk over the three year period (2012-2014). The Company's IRP analyses repeatedly indicate base load coal resources are least cost given the Company's load forecasts and evaluation of future costs and uncertainties. The Company's November Draft 2012 RFP benchmarks are either 840 MW or 915 MW in the two year period (2012-2013) depending on the 2013 benchmark alternative. While not an exact match of MW or time period, we find the amount and timing of coal resource benchmarks in the November Draft 2012 RFP are within, and reasonably consistent with, the Company's IRP preferred portfolios and will serve as reasonable benchmarks against which competitive bids can be compared.

WRA and Sierra Club's interests and concerns will be considered in the RFP evaluation process because the type of resources advocated by WRA and Sierra Club are eligible to bid against the Company's benchmarks to the extent they fit into the base load or exceptional solicitation categories. In this sense, the proposed solicitation will evaluate the Company's benchmarks against alternatives providing similar performance and reliability. Since the evaluation process uses the 2006 IRP analytical tools, including evaluation of a range of potential environmental compliance costs, fuel prices and fuel price volatility, the extent to which lower cost alternatives to the benchmarks are available should emerge.

The Company's July and October Draft 2012 RFP benchmarks are 1,600 MW to 2,290 MW, depending on alternative benchmarks. This amount of benchmark resource is higher than the November Draft 2012 RFP because the Company had intended to solicit bids to replace its planned market purchases of 700 MW. The Division and Committee supported this prior level of benchmark resource and recommend we condition our approval of the RFP on acceptance of certain language changes intended to solicit bids for a higher amount of resources.

Clearly, the RFP falls short of soliciting adequate resources to meet its entire projected deficit. The primary reason for it falling short is that it does not request resources to replace planned market purchases of 700 MW. In order to address reliability of supply, we conclude it is reasonable to solicit bids to fill the 700 MW deficit and suggest the Company modify the RFP to include language that communicates to bidders the Company's intent to contract for power up to 1,700 MW by 2013, as recommended by the Division and Committee.

We note the Company already states in the RFP it may acquire more or less power depending on the quality of bids and other considerations, as noted earlier in this Order. This provides flexibility for using this RFP to acquire timely, cost effective, additional resource.

Further, we are concerned that permitting requirements or other unforseen problems may delay resource online dates and think it reasonable to allow greater flexibility for bidders, as well as for the Company's benchmarks, to meet RFP requested online dates. Given that the resources to be selected through this RFP may have up to 50 year life spans, it is unreasonable to reject potentially sensible resources simply because of a small variation in a feasible online date. Therefore, we concur with the Division and suggest the Company modify the November Draft 2012 RFP to fully consider bids through to 2014.

With respect to the Committee's recommendations regarding inter-jurisdictional cost allocation issues, our December 14, 2004 Order in Docket No. 02-035-04 conditionally approved a method for the inter-jurisdictional cost allocation of new generation resources. This method is also approved in Oregon, Idaho and Wyoming, and therefore is used to set rates for the vast majority of PacifiCorp customers. Our Order stands until it is modified based on evidence provided and a new decision is made. Therefore, we find it premature to rule on, or consider in this case, any alternative method for the cost allocation of those resources that may be constructed or acquired through this RFP. We are certainly cognizant that each state commission must render decisions regarding PacifiCorp's activities that are consistent with its state's laws and evidentiary proceedings. We respect this process and will work to address issues as they arise.

With respect to ongoing IRP analysis and its role in this solicitation process, we fully expect the Company to bring forward its most current IRP analysis that affects this solicitation. Indeed, the November Draft 2012 RFP explicitly states, "the Company may opt to contract for more or less power, depending among other things, on the quality of bids received in response to the RFP, updates to the Company's forecasts, regional transmission availability and timing, and changes in the wholesale energy market conditions." It is the Company's obligation to make decisions based on the best available information at the time and to be judged for its actions given available information and prudent management.

C. LIABILITY WAIVER FOR THE INDEPENDENT EVALUATOR

The Commission-appointed IE requests liability protection while undertaking its duties for the Commission in the RFP solicitation process. The IE believes it should not be subject to lawsuits for its work on the RFP and recommends the Commission's Order specifically state that a waiver of liability against the IE is a condition of participation by the bidders in this RFP process; this waiver could be modeled after Attachment 15 to the RFP which is the language the Company provides to obtain a liability waiver for itself.

The Company is neutral on the issue but believes it is an issue for the Commission to decide. The Division states that since the Commission has sovereign immunity and the Company has a waiver of liability through conditions of participation in the RFP, it is just and comparable for the IE to receive equal protection. The Committee agrees the IE should not be subject to lawsuits for their work on the RFP, but believes the Commission does not have the authority to waive claims of liability as only the Legislature has that authority. The Committee would like to inquire with an Assistant Attorney General specializing in the area of governmental immunity to determine whether the liability protection under the Governmental Immunity Act of Utah also applies to the IE as this position was created by statute. In addition, the Committee is unsure of the nature of the liability for which the IE is seeking protection and believes there is confusion regarding the private commercial contract and the work the IE is performing on the RFP. The IE testifies both its contract with the Commission and Utah statute are silent on this issue.

The Commission suggests the Company add a section, similar to Attachment 15, to the RFP stating that bidders, as a condition of participation in the RFP process, agree to indemnify and hold harmless the IE for its actions associated with the RFP process.

D. COMPARABILITY AND PRICING INDICES

Given the long lead times for the construction of capital intensive resources, the IE is concerned bidders will either include a risk premium in their capacity prices and disadvantage their bids relative to the utility's benchmark resources, or they will simply decide not to compete in the bidding process. In order to permit bidders to provide bids more comparable to those of the utility, the IE proposes, for example, that bidders be allowed the option of indexing certain components of the capacity price to reflect changes in specific cost components from the time the bid is submitted until the time the Engineering, Procurement and Construction ("EPC") contract is executed or the bidder achieves project financing, but no longer than two years after contract execution. The IE also proposes that no more than 50 percent of the initial capacity price be indexed and that the benchmark resources also be eligible to index cost components. UAE supports the IE's proposal, and offers specific language to be incorporated into the RFP.

The Company and the Committee oppose the IE's proposal. The Company states traditional regulatory principles would not permit it to achieve regulatory approval for multi-million dollar generation projects with comprehensively indexed and undefined costs.

The Committee states the IE's proposal results in an unwarranted shift of risk from bidders to ratepayers. Under traditional cost-of-service regulation, the Company bears the burden of establishing that all costs are reasonable and is subject to a prudence review of all costs for which it seeks recovery, including cost increases occurring during the construction period. If bidders are allowed to index capacity prices, ratepayers will bear these costs without the opportunity for parties to review the reasonableness and prudence of such costs since the contracts will be pre-approved. Further, the Committee states the IE's proposal alters the relationship between risk and reward to the benefit of bidders at the expense of ratepayers. With a Company resource, ratepayers obtain the benefit of the resource over its economic life, whereas with a contract, a winning bidder retains the economic value of the resource once the contract has expired.

While we concur owned and purchased resources have different risk characteristics to customers as described by the Company and Committee, we find an indexing option that is carefully and narrowly constructed may improve the number of bids and therefore the options for low cost supply to customers. It is our intent this RFP be designed to solicit as many offers to meet the objectives of the RFP as possible. Therefore, we suggest the Company include an option for specific indexing in the RFP, for bids and benchmarks, and suggest the Company, together with the IE and Division, identify the components of cost eligible for the up to 50 percent capital cost index, the indices that will be used for each component, and the time frame for indexing.

Another comparability issue is raised by UAE. UAE recommends the elimination of the first paragraph on page 52 of the November Draft 2012 RFP in item 4, “Step 4 - Final Selections; Other Factors.” This paragraph describes differences between cost of service regulated entities and market based entities and states the Company assumes that the benefits and risks of these differences are equal and offsetting between benchmark portfolio options and solicitations received through the RFP. No party opposes this recommendation. Hearing no opposition, we accept UAE’s recommendation and suggest the Company modify its November Draft 2012 RFP to exclude this paragraph.

E. CREDIT REQUIREMENT FLEXIBILITY

LS Power believes bidders should be allowed to propose their own credit support requirements and be allowed to negotiate mutually acceptable credit arrangements with the Company in order to balance the need for performance assurance with the costs associated with providing such security. The Company opposes this approach because the basis for meeting credit requirements will not be transparent to bidders. The Company argues transparent credit requirements are crucial to a successful solicitation process and points to the failed negotiations with Calpine that occurred during the final stage of the Company’s last bidding process. UAE supports the position of LS Power, and offers specific language to be incorporated into the RFP.

The IE believes the Company has developed a credit methodology which will be fair, equitable, and balanced to all bidders and will not discourage bidders from competing in the process on the basis of credit requirements. In addition, the IE commends the Company for its approach. The Division does not have any substantive problems with the credit issues but will reserve final judgment pending responses from any potential bidders.

While we understand LS Power and UAE's position, we are concerned accommodation of alternative methods for complying with credit requirements in the negotiation stage will be cause for disputes and a lack of transparency to bidders. We are satisfied the credit requirements will not unduly discourage bidders. We accept the Company's proposed process regarding credit requirements.

F. CO2 ISSUES

1. Modeling of CO2 Regulatory Risk

To evaluate the potential costs of a government mandate to control or manage carbon emissions, the Company proposes applying an $8 per ton cost to the CO2 emissions of bids in the initial short list process. The cost is applied per eligible resource category. Initial short listed bids are evaluated in the Capacity Expansion Model ("CEM") under a range of CO2 costs consistent with the 2006 IRP process, for example, $0, $8, $10, $25, and $40 per ton. Then, optimum portfolios are developed based on the different assumptions, and a final short list of bids is identified.

WRA is supportive of the Company's evaluation approach but believes the Company's use of an $8 per ton CO2 adder as its base case is too low. WRA provides evidence documenting that the price per ton for CO2 in the European Union has fluctuated significantly over the past year but is consistently above the equivalent amount of $8 per ton.

We recognize there is significant value derived from understanding the different potential costs associated with scenarios regarding how CO2 emissions will be dealt with in future years. We also recognize that even if imputed as part of the evaluation process, no actual costs would be incurred until Congress acts to impose some type of tax, cap or other constraint. Recognizing that costs are uncertain, and do not currently exist, the issue becomes identifying the correct reasonable premium, if any, to pay to mitigate these uncertain costs.

This docket has not developed a sufficient record to enable the Commission to decide at this point, an appropriate CO2 cost assumption to be used in this RFP. Faced with an insufficient record and such a significant variation in possible outcomes, the Commission supports the use of a full range of potential CO2 costs in all but the initial short list stage of the evaluation process so the opportunity costs of selecting one technology over another are made clear and explicit in the selection process. However, we suggest a modification to the initial short list evaluation stage of the RFP. Here, the $8 per ton CO2 cost is applied to competing resources in eligible resource categories that are not fuel specific. We suggest the Company modify this process so that resources in the initial short list are selected as lowest cost by each fuel type within each eligible category. This would ensure the lowest cost natural gas as well as lowest cost coal bids advance to the stage of the evaluation that considers the full range of potential CO2 costs.

Further, we suggest the Company report the full blinded present value revenue requirement results of each of the different CO2 cost scenarios to the Commission and intervening parties, at the following steps of the evaluation process: 1) at Step 2, CEM, production cost run (at a minimum this would require each of the optimal portfolios for each of the CO2 cost scenarios to be reported - along with the supporting results of the analysis); and 2) at Step 3, risk analysis, again an optimal list for each different CO2 cost scenario.

Thus, at each point in the evaluation process the Commission, and the intervening parties, will have the best estimates of the full opportunity cost of each competing technology and approach, as well as the supporting evidence leading up to each of the optimal short lists. This approach should assist in developing sufficient information for parties to argue their positions regarding the cost and risk mitigation tradeoff of alternative resources and for the Commission to make a decision regarding the next stage of the RFP selection process. The Commission will rely on the parties to advocate, either at that point or in a future docket, for allowance or disallowance of the extra incremental costs resulting from the Company's decisions.

2. CO2 Risk Allocation

For asset-backed power purchase agreement (PPA) bids, asset purchase and sales agreement bids and the Company's benchmark, the Company proposes to bear the risk if there is a change in law and a CO2 tax or constraint imposed. In both the evaluation of proposals and benchmarks, the CO2 cost is passed through to the Company and it is assumed to pass through to ratepayers. The Company will consider change to this CO2 risk allocation in final contract negotiations.

The IE advocates the change in law risk be the same for the bidder of a PPA as for the Company. That is, the same standard of facts and same contract prudence review would apply to the PPA and the Company's resources for complying with a change in law associated with CO2. The IE is concerned there may be less expensive ways than simply paying the tax in order to comply with this change in law and therefore, contracts should be allowed to be modified to include, for example, retrofit costs to comply with such change in law.

We concur with the IE that the same standard of facts and same prudence review shall apply to the PPA and the Company for complying with a change in law associated with CO_2. That is, changes to contract pricing based on CO_2 compliance costs will be reviewed (and approved) by this Commission prior to being passed through to customers. This will ensure ratepayers, with respect to this issue, are indifferent between a Company-owned resource and contractual supply. We suggest the RFP be modified, to the extent this is necessary, to address this issue.

G. INNOVATIVE BID PROPOSALS

WRA recommends increasing the flexibility of the RFP process and recommends the Company accept non-conforming bids, such as joint ownership agreements, within the IGCC eligibility category which would enable a bidder to propose development of an IGCC unit, with the bidder owning the syngas unit and selling syngas to the Company, and the Company owning the balance of the plant.

WRA advocates this concept and comments that since the bidder would have a greater degree of operational control of the syngas unit under this arrangement the bidder may be willing to provide better performance guarantees than if it were to hand over operational control of the entire unit to the utility. No other party provides comments on this issue.

It is our goal that this RFP solicitation encourage the receipt of as broad a range of proposals as possible. The November Draft 2012 RFP eliminates the non-price weighting factor addressing compliance with the pro forma agreements, requires the successful IGCC bidder to enter into a 12-year operations and maintenance agreement with the Company, and includes the ability to offer alternate proposals. While we encourage the Company to ensure the

RFP results in the receipt of as many broadly diverse proposals as possible, it is our view the RFP as proposed contains latitude for this type of bid and no further modifications to the RFP are suggested to explicitly address this issue.

III. SUMMARY OF SUGGESTED MODIFICATIONS

Wherefore, pursuant to our discussion, findings and conclusions made herein, we suggest the Company modify the November Draft 2012 RFP for Base Load Resources as follows:

1. Include language that communicates to bidders the Company's intent to contract for power up to 1,700 MW;
2. Fully consider any bid through to 2014;
3. Add a section to the RFP, similar to Attachment 15, stating that bidders, as a condition of participation in the RFP process, agree to indemnify and hold harmless the IE for its actions associated with the RFP process.
4. Provide an indexing option for capital costs, consistent with this Order.
5. Eliminate the first paragraph on page 52 of the November Draft 2012 RFP in item 4, "Step 4 - Final Selections; Other Factors."
6. In the initial short list evaluation process, select resources by fuel type within each eligible resource category for advancement to the next steps of the evaluation process. Identify the opportunity cost of complying with alternative CO_2 cost scenarios for each portfolio modeled in steps 2 and 3 of the evaluation process.

7. To the extent necessary, provide language to clarify that changes to contract pricing based on CO_2 compliance costs will be reviewed (and approved) by this Commission prior to being passed through to customers.

DATED at Salt Lake City, Utah, this 21st day of December, 2006.

/s/ Ric Campbell, Chairman

/s/ Ted Boyer, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#51889