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July 13, 2005

VIA ELECTRONIC FILING

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attention: Vikie Bailey-Goggins, Administrator
Regulatory and Technical Support

RE: LC-39 Integrated Resource Plan
Responses to PacifiCorp's Integrated Resource Plan

PacifiCorp (dba Pacific Power & Light Company) submits for electronic filing, PacifiCorp's Responses to Comments on PacifiCorp's 2004 Integrated Resource Plan. A signed letter and five conformed copies of the filing will be provided via Federal Express tracking number 7929-7305-7444.

It is respectfully requested that all formal correspondence and Staff requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com.

By Fax: (503) 813-6060

By regular mail: Data Request Response Center
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Informal inquiries may be addressed to me at (503) 813-6711.

Sincerely,

Melissa A. Seymour

Melissa A. Seymour
IRP Manager

cc: LC-39 Service List
Katherine McDowell, Stoel Rives

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that on this 13th day of July, 2005 I caused to be served, via US Mail or email to those with an email address, a true and correct copy of the Responses to OPUC Staff's Comments on PacifiCorp's Integrated Resource Plan (Docket No. LC-39).

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Response to Staff's Draft Proposed Order on PacifiCorp's Integrated Resource Plan

(Docket No. LC 39)

INTRODUCTION

On June 27, 2005, pursuant to the March 21, 2005 Prehearing Conference Memorandum, Oregon Public Utility Commission Staff (Staff) filed its Comments and Recommendations (Staff Comments) on PacifiCorp's 2004 Integrated Resource Plan (2004 IRP) and a Draft Proposed Order (Draft Order). PacifiCorp hereby files these comments and recommendations in reply to the Staff Comments and Draft Order.

SUMMARY OF COMMENTS AND RECOMMENDATIONS

PacifiCorp appreciates the collaborative and informal nature of Oregon's IRP process and the helpful role that Oregon Commission Staff plays in shaping the IRP in the public process. However, the Company notes that the positions in Staff's Comments and Draft Order on PacifiCorp's Planning Margin, the CY 2011 resource, and other issues were raised after the conclusion of the public input process rather than during the year-long process. In the Company's view, one purpose of the public planning process is to allow all parties to discuss recommendations such as those presented in Staff's Comments and Draft Order to enable parties the opportunity to develop a consensus and provide the Company with time to consider the merits of the recommendations in the final plan. Given the multi-state nature of PacifiCorp's IRP, a full airing of issues in the IRP public planning process is particularly important.

In the spirit of collaboration, , PacifiCorp has stipulated to many of the changes Staff proposes to PacifiCorp's IRP and Action Plan, including Staff's proposed additional Action Item 1 (increased DSM), additional Action Item 2 (ETO agreement), additional Action 3 (expanded renewables modeling), additional Action Item 5 (DSM modeling), additional Action Item 6 (modeling interruptible contracts), additional Action Item 8 (IGCC assessment), and additional Action Item 10 (transmission modeling).

Because PacifiCorp relies heavily upon its IRP, the nature and form of the Commission's acknowledgment of its IRP is critical to PacifiCorp. For this reason, on the following points implicating fundamental building blocks of PacifiCorp's IRP—including principles currently at issue before the Commission in UM 1056—PacifiCorp cannot agree to Staff's position: (1) Staff's recommendation against acknowledgement of a second large thermal resource, including a coal plant by the summer of 2011; (2) Staff's additional Action Item 4 (DSM study); (3) Staff's additional Action Item 7 (modeling Class 3 DSM); (4) Staff's additional Action Item 9 (modeling Planning Margin cost-risk tradeoffs and evaluating Class 3 DSM for meeting unserved energy); (5) Staff's additional Action Item 11 (scenario modeling of Combined Heat and Power).

PacifiCorp respectfully submits that these recommendations exceed the appropriate scope of an acknowledgement proceeding, prejudge issues currently pending in UM 1056, and are unsupported by the weight of the credible information and analysis available in this proceeding. For these reasons, PacifiCorp requests that the Commission reject Staff's proposed recommendations and instead issue an order acknowledging the 2004 IRP and Action Plan as outlined below.

1. Staff's Proposed Recommendations Exceed the Proper Scope of Commission Review in an Acknowledgement Proceeding.

In Staff's Comments, Staff recommended that the Commission acknowledge the 2004 IRP—with the notable exception of the 2011 thermal resource—and made 11 modifications to the Action Plan. (Staff Comments at 12.) With respect to the recommended Actions, it is important to note that only one modifies an action item actually included in PacifiCorp's Action Plan. The other 10 recommended Implementation Actions add new actions to the Action Plan. Of those 10 additional implementation actions, only one relates to the current Action Plan. The remaining 9 modifications all relate to the next IRP or Action Plan (each begin with the following phrase, "For the next IRP or Action Plan . . .") and require PacifiCorp to undertake some different or additional analysis in that next cycle regardless of input received from other stakeholders. (*Id.* at 13-14.) Staff recommends that the Commission require the recommendations be "conditions for acknowledgment". (*Id.* at 14). As noted above, in the interest of compromise and collaboration, PacifiCorp has agreed to the majority of these recommendations.

With respect to the proposed additional Action Items 4, 7, 9 and 11, PacifiCorp submits that conditioning acknowledgment of this 2004 IRP on what PacifiCorp must do after the public input and process for the next IRP is beyond the proper scope of an acknowledgment proceeding.[1] In the Commission's Least Cost Planning Order (No. 89-507)[2], the Commission adopted a planning requirement for all utilities. *Re Least-cost Planning for Resource Acquisitions*, Docket UM 180, Order 89-507 (OR PUC April 20, 1989). The approach was designed to provide a "thorough" yet "flexible" approach to utility planning and provide an opportunity for public input in the planning process "at its earliest stages." *Id.* The result of the IRP process is to be "the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs." *Id.*

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[1] PacifiCorp acknowledges that some of the agreed-upon, Staff-recommended modifications also are based on conditioning approval of this IRP on requirements for the next IRP. Nevertheless, PacifiCorp has agreed to these recommended modifications and not the others because the agreed-to modifications do not implicate the key policy considerations that PacifiCorp does not agree with. Those policy considerations are discussed in the next section of these comments.

[2] Order 89-507 is still good law in Oregon controlling IRP procedural and substantive requirements. While the Order is being reviewed in Docket No. UM 1056, it has never been overturned or rejected outright by this Commission.

The Commission laid out six procedural and four substantive requirements that are to be observed by utilities in the planning process. *Id.* Utilities were directed to file plans every two years which would be reviewed by the Commission for "adherence to the principles enunciated in [Order 89-507] and subsequent orders." *Id.* This review was intended to result in an "acknowledgement" order. *Id.* The Commission defined "acknowledgment" as follows: "Acknowledgment of a plan means only that the plan *seems reasonable* to the Commission *at the time the acknowledgment is given*." (*Id.* (Emphasis added.))

The Commission's Order 89-507 provided a framework for proceeding with plans that as filed could not be acknowledged: "If further work on the plan is needed, the Commission will return it to the utility with comments. This process should eventually lead to the acknowledgment of the plan." In a later order, the Commission clarified that in an acknowledgment decision it was stating "its opinion about what resource strategies or actions are reasonable" in order to "provide clear guidance to the company." *Re Portland General Electric*, Docket LC 2, Order No. 91-1552 (Or. PUC Nov. 8, 1991). In providing this guidance, the Commission made clear that it can either "return a plan for further work or acknowledge the plan with modifications included to make the plan reasonable."[3] *Id.* The Commission also stated that it considers comments from all parties in reaching its final determination on acknowledgment. PacifiCorp has relied upon these existing OPUC guidelines and has conducted its IRP process in accordance with the defined requirements.

Staff's proposal to condition acknowledgment of this 2004 IRP on addition of items to the current Action Plan that would require untried, potentially controversial analysis to be conducted in the next IRP is inconsistent with this acknowledgment framework. The 2004 IRP should be judged a reasonable plan (with or without modifications to the plan) given what is known and knowable *at this time*. PacifiCorp concedes that Order 89-507 contemplates that the requirements for planning may evolve over time and be supplemented by subsequent orders. Indeed, the Commission has in previous acknowledgment orders ordered the utility (and at times, other parties) to engage in processes to better analyze certain issues before and during the next IRP cycle. This is the inherent benefit of the flexibility of Order 89-507 recognized by the Commission at the time. However, while the analysis process can and should evolve over time, the consideration and determination of what is a reasonable plan at this time should not be dependent on that further analysis. Instead, the Commission's order contemplates that the Commission will look to the analysis and information available in this IRP cycle from all parties and determine if the plan "seems reasonable." (Order 89-507.)

The Commission's later orders in least-cost planning filings by PacifiCorp and other utilities confirm this interpretation of Order 89-507. This Commission has not heretofore conditioned acknowledgment of one IRP on Staff's recommendation to include action items in that IRP for

[3] The Commission acknowledged that its proposed "modifications" are not mandatory obligations of the utility. For example, the Commission recommended certain actions for utility near-term conservation activities in LC 2. In doing so, the Commission stated that it "recognizes that [the utility] is not required to comply with these recommendations." Rather, utility management still bears the ultimate responsibility as to resource decision. If the utility's decisions are consistent with the acknowledgment order, then the utility "may face a greater likelihood that its actions will be judged prudent and the costs allowed in a future rate case." If the utility chooses to take actions inconsistent with the order, it must be prepared to explain why it has taken those actions.

the next IRP over the utility's objection[4]. Instead, where parties offer suggestions for improvement in the IRP analysis, the Commission has either ordered PacifiCorp (or other utilities) to study the issue and report back to Staff and the Commission[5] or where the record is clear as to the need for the additional analysis, the Commission has simply ordered the utility to undertake the analysis in the next cycle.[6]

Staff has previously recognized the distinction between modifications proposed to make the current IRP reasonable and those suggestions proposed to improve the next planning cycle. For example, in LC 6, PacifiCorp's second integrated resource plan filing, Staff made 23 separate recommendations on the IRP and Action Plan.[7] The first 11 modifications proposed changes to the current Action plan. The next 10 suggested steps for PacifiCorp to undertake in performing future resource planning activities and the final two recommended non-acknowledgment of two aspects of the plan. In its order, the Commission adopted modifications to the then-current Action Plan and with those modifications acknowledged the plan. The Commission also ordered PacifiCorp to undertake certain but not all of Staff's proposed steps for the next planning cycle. The Commission's ultimate order recognized the distinction between taking action on the plan then under review and adopting proposals for making the next cycle better: "RAMPP-2 should be acknowledged with the modifications to the Action Plan adopted above. In addition, PacifiCorp should undertake the other actions discussed above in preparing * * * its next integrated resource plan."[8] While both types of proposals (modifications to current plan and recommendations for future plans) are properly within the purview of the Commission's IRP review, there is no reasonable basis for linking the two.

PacifiCorp respectfully submits that the Staff Comments which propose that the Commission condition acknowledgment of 2004 IRP on adding additional action items related to the next IRP cycle are beyond the scope of the Commission's acknowledgement review as laid out in its

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[4] Staff has previously recommended that the Commission acknowledge a utility's plan subject to modifications that included adding action items into the current plan which dictate how the Company would approach planning in the next cycle. However, it appears that while the Commission has adopted such modifications, it has done so only where the utility has agreed to the modifications. *See, e.g., Re Pacific Power & Light Co.*, Docket LC 1, Order No. 90-1658 (OR PUC Nov. 9, 1990) (utility agreed to all Staff's recommendations), *Re Portland General Elec. Co.*, Docket LC 2, Order No. 91-1552 (OR PUC Nov. 8, 1991) (utility disagreed with some recommendations but those did not involve changing current action plan to require certain analysis in the next IRP cycle); *Re Northwest Natural Gas Co.*, Docket LC 3, Order 91-822 (OR PUC July 1, 1991) (utility agreed to all staff recommendations) .

[5] For example, in PacifiCorp's first least cost planning filing with the Commission in Docket LC 1, a party recommended that a CO_2 adder be included in resource costs. PacifiCorp tested an adder with a different value and developed a scenario to reduce CO_2 emissions. *See Re Pacific Power & Light Co.*, Docket LC 1, Order No. 90-1658 (OR PUC Nov. 9, 1990). Staff found that PacifiCorp's treatment of external costs was a "reasonable first effort." *Id.* Rather than requiring additional analysis prior to issuing an order acknowledging the IRP, the Commission reached the same conclusion as Staff—for purposes of that IRP, PacifiCorp's analysis was "reasonable". *Id.* However, the Commission directed Staff to recommend a process for investigating the issues related to externalities. *Id. See also Re Cascade Natural Gas Corp.*, Docket LC 20, Order No. 98-104 (OR PUC March 16, 1998); *Re Northwest Natural Gas Co.*, Docket LC 29, Order No. 00-782 (OR PUC Dec. 11, 2000); *Re Idaho Power Co.*, LC 32, Order No. 03-389 (OR PUC July 3, 2003).

[6] *See e.g., Re PacifiCorp*, Docket LC 31, Order No. 03-508 (OR PUC Aug. 25, 2003) (ordering PacifiCorp to develop, with public input, a methodology for determining an appropriate capacity value for wind resources).

[7] *See Re PacifiCorp*, Docket LC 6, Order No. 93-206 (OR PUC Feb. 12, 1993); *See also Re Portland General Elec. Co.*, LC 7, Order No. 93-804 (OR PUC June 11, 1992).

[8] *See Re PacifiCorp*, Docket LC 6, Order No. 93-206 (OR PUC Feb. 12, 1993).

guidelines. While the Commission can appropriately order PacifiCorp to consider additional analyses in its next cycle as a refinement on Order 89-507, it should not, contrary to its own precedent upon which PacifiCorp has relied in preparing this IRP, confuse those future refinements in the process with the determination of the reasonableness of the IRP currently before it. For those reasons, PacifiCorp requests that the Commission reject Staff's additional Action Items 4, 7, 9 and 11.

2. The Commission Should Not Prejudge Issues Currently Pending Before It in Another Commission Proceeding Prior to Hearing From All Parties on Those Issues.

Staff's additional Action Items 4, 7, 9 and 11 raise an additional concern which justifies Commission rejection of these changes at this time. These issues are squarely before the Commission in another proceeding, UM 1056. It is inappropriate for Staff to condition acknowledgment of the 2004 IRP on unresolved but pending issues in another docket. Because these issues are pending in UM 1056, the Commission should not adopt these recommended modifications even as refinements in the planning process at this time.

The Commission opened Docket UM 1056 in December of 2003 in order to "reconsider the fit between traditional least cost planning and a competitive industry, and to reopen an investigation to review least cost planning requirements."[9] The docket was suspended until a final order was issued in Docket UM 1066. Activity resumed in the docket early this year after the UM 1066 order was issued. Joint issues list in UM 1056 were filed by the parties on April 21, 2005. This Commission adopted the joint issues list by Memorandum issued June 6, 2005.

Staff's recommended Additional Action Items 4, 7, 9 and 11 fall squarely into issues included on the Commission-approved issues list in UM 1056. Specifically, Staff recommended additional Action Item 4 requires PacifiCorp to conduct an economic analysis of achievable Class 1 and Class 2 DSM measures and compare the Company's base and planned programs with the cost-effective amounts determined in the study. Staff's recommended additional Action Item 7 requires PacifiCorp to determine expected load reductions associated with Energy Exchange and interruptible contracts at various prices and model them as Class 3 DSM resources competing with other supply side options. These two recommended Implementation Actions fall squarely into Issues 13 and 14 on the UM 1056 approved issues list: "How should cost-effective conservation be analyzed and included in resource planning? Should a conservation potential study be conducted and if so, how?" and "How should demand response be explicitly included in integrated resource planning on par with other options for meeting energy and capacity needs?"

Likewise, Staff additional Action Item 9, dealing with Planning Margins, is squarely before the Commission in UM 1056 under Issue 21: "How should the resource Planning Margin be determined to ensure resource adequacy and consider cost?" Since Staff recommends the use of stochastic analysis for assessing Planning Margin levels, Issue 3 is also relevant: "How should

[9] *In the Matter of the Investigation into Integrated Resource Planning Requirements*, Docket UM 1056, Order 02-546 (OR PUC Aug. 8, 2002).

integrated resource plans measure and consider the cost-stochastic risk tradeoff between candidate resource portfolios?" Finally, recommended additional Action Item 11, dealing with CHP and aggregated dispatchable customer standby generation will be addressed in UM 1056 under Issue 20: "How should distributed generation be addressed in integrated resource planning?"

The wording of the issues on the UM 1056 approved issues list leaves open for party comment and Commission consideration whether certain items should be considered and modeled in IRPs and if so, how that modeling and analysis should be conducted. Staff's recommended modifications predetermine the outcome of these issues in at least two respects. First, by including additional Action Items 4, 7, 9 and 11 as conditions to acknowledgment of this 2004 IRP, Staff effectively predetermines that these issues can and should be considered in the next IRP. Second, Staff has proposed with some specificity the parameters of the analysis of these issues in its suggestions included in the recommended modifications. If adopted, these recommended modifications would therefore also predetermine how best to model and analyze these issues.

Accordingly, if the Commission were to choose to adopt Staff's recommended Implementation Actions, it would be tantamount to predetermining the outcome in UM 1056 on these issues prior to hearing from all parties. In addition, even if the Commission were inclined to address those issues in this docket, it is premature to reach a decision on these issues. Currently, as discussed in detail below, PacifiCorp does not agree that these recommended Implementation Actions are appropriate as written. However, while parties in the UM 1056 docket have undertaken extensive and ongoing dialogue through the workshop process, the docket has not yet concluded and the Commission has not yet heard from all parties on these issues. Parties have another workshop scheduled and have yet to file opening and reply comments. PacifiCorp requests that the Commission reject Staff's recommended Implementation Actions on this basis and await the full exploration and presentation of those issues in Docket UM 1056.

For all the reasons discussed in the foregoing and subsequent sections, PacifiCorp requests that the Commission acknowledge PacifiCorp's 2004 IRP and Action Plan with only the modifications discussed herein and reject Staff's recommended additional Action Items 4, 7, 9 and 11. As a compromise solution, PacifiCorp proposes that the Commission's resolution of these issues in UM 1056—DSM, demand response, planning margin and CHP—be incorporated in PacifiCorp's next IRP public input process. This approach will provide PacifiCorp and its IRP stakeholders the appropriate forum with which to discuss the implementation details of the Commission's decision on these issues given the IRP's analytical objectives.

DISCUSSION AND DETAILED RECOMMENDATIONS

This section provides specific responses to Staff's comments and recommendations, as well as suggested wording changes to Staff's proposed Commission Disposition and Conclusion sections.

1. Load Forecast

Given PacifiCorp's stochastic analysis approach, PacifiCorp does not agree with Staff that using a scenario analysis that determines the performance of portfolios when load deviates significantly from projections provides added value. In the IRP, PacifiCorp outlined the advantages of the stochastic simulation approach—one of the most important being that it captures the relationships between deviations of load and deviations of other correlated factors, e.g., gas and market prices. Staff's proposed scenario analysis approach does not capture these important effects, and therefore yields results that are different from those obtained from stochastic simulation. In fact, by only considering load variability in isolation, it can yield contradictory and perhaps misleading conclusions regarding the PVRR impact of load growth on various portfolios, as evidenced by the load growth scenario results reported for Staff's data request. Given the clear value of modeling load as part of a stochastic analysis, PacifiCorp would be concerned that additional load-related scenario analysis would complicate the portfolio evaluation process rather than inform it.

PacifiCorp also reaffirms its belief that it would be imprudent to plan on any future other than the expected future given the lead time necessary to acquire certain resources. Stochastic analysis provides ample assessment of load forecast uncertainty while retaining the reasonableness of planning for one expected outcome. PacifiCorp also emphasizes that the IRP and procurement processes can adjust as required if the load forecast picture changes dramatically.

Finally, PacifiCorp continues in agreement with Staff that PacifiCorp should plan to serve the entire forecasted load in Oregon and that this issue should be revisited if the level of direct access participation increases significantly under current regulation or if a revised direct access tariff causes significant increases in the participation of the level of direct access.

PacifiCorp's Suggested Commission Disposition: The Commission expects consideration of several different futures through ~~to see worst case~~ risk analysis in IRPs, including the risk that retail loads could vary significantly above or below forecasts in addition to other variables. Additional scenario risk analysis to evaluate load growth levels is not necessary provided PacifiCorp believes that load variability in the stochastic simulations encompasses suitably high and low extremes. ~~In addition to stochastic worst case analysis that takes into account a number of variables, including retail load fluctuations, the Commission is interested in scenario risk analysis indicates how portfolios may perform if loads deviate significantly from projections.~~

2. Planning Reserve Margin

Staff is not convinced that the Company's 15% Planning Margin is appropriate, and strongly suggests that a 12% Planning Margin represents a better cost-risk tradeoff. Staff outlines its reasons supporting a lower Planning Margin, and makes some methodology recommendations for future IRPs. PacifiCorp addresses each of Staff's reasons below and provides additional support for PacifiCorp's 15% Planning Margin.

In the 2003 IRP process, PacifiCorp was asked by parties to perform a loss of load probability study (LOLP) to determine the appropriate Planning Margin to use for the 2004 IRP. PacifiCorp hired an external consultant, Global Energy Decisions, to perform a sophisticated LOLP study to inform the 2004 IRP. The LOLP study identified an 18% Planning Margin as the appropriate Planning Margin for PacifiCorp's system using a one day in ten year outage criterion. PacifiCorp took the study a step further by projecting the cost-risk trade off of various levels of Planning Margin based on customer's appetite for loss of load (a.k.a. the "bathtub chart"). This resulted in PacifiCorp using a 15% Planning Margin for the 2005 IRP. PacifiCorp felt this was reasonable from an operational perspective since the Planning Margin is to cover WECC Operating Requirement (6-7%), Regulating Margin (1-2%), deviations in expected load, and unplanned outages (PacifiCorp's unplanned outage rate is between 8-10%). This level of Planning Margin is also consistent with what is being used by neighboring utilities.

PacifiCorp discussed the Planning Margin study with the parties during the June 10, 2004 Public Input Meeting (PIM). The results of the cost-risk tradeoff analysis were presented during the July 27, 2004 PIM and a discussion with participants took place as to whether PacifiCorp should allow portfolios to drop below 15% in any year or maintain a minimum of 15% in every year. During the July 27, 2004 meeting, public input participants expressed no objection to PacifiCorp constructing portfolios that maintained a minimum 15% Planning Margin in every year of the plan.

PacifiCorp acknowledges that there is a tradeoff between cost and reliability within system planning. Greater system reliability often comes with increased resource need. However, maintaining a resource level that supplies a lower level of system reliability can impose unacceptable risks; the optimum balance of cost and risk lies somewhere in between both extremes.

There are no universally accepted standard criteria to determine the correct reserve Planning Margin. Existing methodologies require a degree of professional judgment and subjectivity. Many of the NERC sub-regions use a LOLP metric of 1 day in ten years to determine the reserve Planning Margin. Using this metric the Planning Margin study produced an 18% Planning Margin. The 15% Planning Margin derived from the "bathtub chart" is equal to a 2.2 days in ten years LOLP or 220% of the common planning metric—more risky, but appropriate given the study results. A 12% Planning Margin would lead to an even higher LOLP of about 5 days in ten years, or 500% of this common planning metric, a risk level too high for PacifiCorp given its obligation to serve customers with reliable, low cost power.

Staff notes that the all-in stochastic cost for the 12% stress case was only 0.2% higher compared to Portfolio E, with an upper tail PVRR (average of five worst results) just 1.2% higher, which would support a 12% Planning Margin. However the average PVRR for Portfolio E is still statistically lower than the PVRR for the 12% Planning Margin case (Figure 8.13, pg. 141). Also, the upper tail PVRR of the 18% Planning Margin is only 1.8% higher than the upper average PVRR for Portfolio E, which would support going to a more reliable 18% Planning Margin indicated in the Planning Margin study. Thus, this comparison is not helpful for supporting a specific optimal Planning Margin level, but rather highlights the point that a range of Planning Margin levels is economically similar.

Staff is skeptical of the unserved energy costs PacifiCorp used in its Planning Margin analysis, and expressed concern that the costs may be out-of-date, are not from PacifiCorp's service area, and are very high. Given the broad spectrum of unserved energy costs used in the study (from a low of $5,210 to a high of $44,910), PacifiCorp feels unserved energy costs have been adequately represented. PacifiCorp is aware of at least one utility, LG&E Energy, that used the EPRI system reliability study results in their most recent IRP for determining unserved energy cost values. This is noteworthy in that PacifiCorp has not set the precedent for using this study in an IRP context, and other utilities view the data as useful for reliability cost-risk tradeoff analysis. PacifiCorp also points out that Staff's statement that the weighted average unserved energy value ($24,000/MWh) was used to set the Planning Margin is incorrect. We noted in the IRP and again in the "Response to Oregon Party Comments" document that we applied a number of criteria to select the 15% Planning Margin level. Further, we did not rely on any specific value in the bathtub chart for the cost-risk tradeoff analysis due to the flatness of the cost curve segments that define the economic efficiency zones for the various customer classes. We merely note that 15% is representative of the bottom of the curves. (See page 222 of the IRP Technical Appendix:, "when considered on a whole, 15% is representative of the bottom of the curve for the system.")

Staff also notes that demand response programs such as interruptible contracts, energy buyback programs, and voluntary load reduction programs should be factored into the costs used. Staff further states that such programs could make a Planning Margin higher than 12% more attractive, but were not included in the Planning Margin or portfolio analyses. PacifiCorp agrees with Staff that demand response programs are helpful to reliability and may reduce the need to procure resources. However, the Company argues later in this document (Section 3, Demand Side Management) that the non-firm nature of Class 3 DSM precludes reliance on this resource for long-term system capacity and reliability planning purposes.

Staff points out that in July 2004 the Commission acknowledged for Portland General Electric's IRP a Planning Margin of 12%, consisting of 6% operating reserves as required by WECC and an additional 6% planning reserve, all under average hydro conditions. *See Re Portland General Electric Co.*, Docket LC 33, Order No. 04-375 (OR PUC July 20, 2004). PacifiCorp submits that this is a misleading comparison. Portland General Electric's (PGE) Planning Margin was derived with a different methodology. The underlying assumptions, system size, average unit size and outage rate, resource mix, and actual modeling approach used can cause differences in the resulting reserve Planning Margin.

Staff notes that the Planning Margin was determined on the basis of meeting the single peak hour of the year. Staff points to studies requested of the Company that show that planning to the average of the eight super-peak hours for the Eastern control area reduced the Planning Margin by some 200 MW in FY 2011 and FY 2012. Staff then notes that the revised obligation amount had no impact on the timing of the capacity additions in Portfolio E. PacifiCorp agrees that planning to the average of the super-peak hours would lower the apparent Company obligation and corresponding Planning Margin. However, PacifiCorp does not think it is prudent to undermine its obligation to serve by planning to a level less than its peak obligation. This strategy would transfer to PacifiCorp and its customers increased risk of adverse reliability and economic consequences. Staff does not specify how PacifiCorp should manage the additional 200 MW of load quoted if the Company should plan to a super-peak average load.

Staff advises that the Planning Margin be an analysis variable in the modeling of all portfolios. Staff asserts that the methodology used by the Northwest Planning and Conservation Council in its Fifth Power Plan to analyze the appropriate Planning Margin is superior to PacifiCorp's methodology. PacifiCorp acknowledges that, as pointed out above, there can be different approaches to LOLP methodologies used in developing Planning Margins. PacifiCorp's Planning Margin study, described in detail in appendix N, is the same methodology used by several large utilities in the WECC for developing their Planning Margins. The Company has identified no reason to use a different approach than that used in its study, an approach deemed reasonable and seen as adequate by many other stakeholders.

Staff recommends that for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp should determine the appropriate Planning Margin by analyzing the cost-risk tradeoff of various Planning Margins within stochastic modeling of portfolios, rather than as a separate analysis as in the 2004 IRP. Ideally, Staff recommends that the Company analyze the cost-risk tradeoff of all portfolios at various Planning Margins. At a minimum, Staff recommends that the Company initially build all portfolios to a set Planning Margin, test them stochastically, and adjust top-performing portfolios to higher and lower Planning Margins for further stochastic evaluation. Staff also recommends that the Company evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Reserve Planning Margin is a control area or system metric based on a LOLP study of that specific system; it is not a variable that changes with each portfolio being evaluated to meet future system needs. As such, Staff's recommendation is unnecessary. Additionally, PacifiCorp has no way to model stochastically the Planning Margin within its existing model, and is not aware of a model that can perform this type of analysis. Given that the model cannot perform the stochastic analysis on the Planning Margin, scenario analysis for informational purposes at a 12% and 18% reserve margin is appropriate.

PacifiCorp's Suggested Commission Disposition: While the Commission agrees that the assumed costs to customers of unserved energy and costs for reducing it are disputable, there is no basis to judge 15% as being an unreasonable planning margin given PacifiCorp's IRP analysis and its consistency with current industry practice. The Commission expects to revisit PacifiCorp's Planning Margin analysis approach subsequent to the outcome of the UM 1056 proceeding and in light of regional adequacy standards being investigated and developed.
~~PacifiCorp's IRP analysis does not satisfy that its proposed 15% Planning Margin is appropriate. The 12% Planning Margin stress case portfolio is less costly on a deterministic basis, and its expected stochastic cost and upper tail cost are similar to Portfolio E which includes a 15% Planning Margin. The assumed costs to customers of unserved energy, and the cost for reducing it, are disputable. Moreover, the Company did not fully analyze the cost-risk tradeoff of various Planning Margins within stochastic modeling of portfolios. A planning reserve margin of 15% is not acknowledged.~~

~~For its next IRP or Action Plan, PacifiCorp should determine the appropriate Planning Margin by analyzing the cost-risk tradeoff within stochastic modeling of portfolios. In particular, the~~

~~Company should assess the cost risk tradeoff of each portfolio at various Planning Margins, or explain why it cannot do so. In that case, the Company should at a minimum build all portfolios to a set Planning Margin, test them stochastically, and adjust top performing portfolios to higher and lower Planning Margins for further stochastic evaluation. The Company also should evaluate loss of load probability, expected unserved energy and worst case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Further, the Company should evaluate alternatives for determining the expected annual peak demand — for example, planning to the average of the eight hour super peak period, instead of the single peak hour of the year.~~

3. Demand Side Management

Conservation (Class 2 DSM)

PacifiCorp has committed to the acquisition of Class 2 DSM above the base case of 250 MWa based on finding cost-effective DSM opportunities. This will be accomplished through both the RFP process for new opportunities and continuing to improve the results of existing programs in the marketplace. One limitation is how much DSM each state's commission is willing to pay for. Consequently, the Company agrees to this commitment contingent on receiving approval from all state commissions. The Commission Disposition has been edited accordingly.

For the Company's historical resource plans through RAMPP 6, supply curves or "bundles" of DSM programs were modeled as potential resource options (for what we now call "Class 2" resources). Class 1 resources were not considered as resource options prior to the 2003 IRP. As part of the 2003 IRP process, several parties were encouraging PacifiCorp to improve its modeling of DSM and proposed that the Company adopt the "decrement approach" as documented by the Tellus Institute. The Company did adopt this new approach for both the 2003 and 2004 IRPs. The Company has since improved modeling of Class 1 resources because their characteristics can be modeled in a similar manner to supply-side resources.

By suggesting the Company develop supply curves for Class 2 programs and use this type of analysis in the next IRP, the Company would be taking a step backwards to the type of analysis conducted prior to the 2003 IRP. The Company is always open to improving DSM analysis; however, in consideration of the multi-state agreement to the decrement approach and the situs nature of DSM expenses, consultation with all parties needs to be considered before once again changing the DSM analysis approach. While the Company therefore agreed to the recommended new Action Item 5, it anticipates that development of the modeling approach will be a collaborative process among parties for the next IRP.

Regarding Staff's recommendation to have PacifiCorp conduct an economic analysis of achievable Class 1 and Class 2 DSM measures, the Company stresses that DSM costs are situs to each State; therefore, state commissions must decide if they see value in funding a DSM market potential study for their customers. As mentioned earlier, such considerations are properly dealt with in the context of the public input process and the UM 1056 proceeding, not this IRP docket.[10]

Price Responsive Load Reduction (Class 3 DSM)

Apart from the Company's objection to Staff's recommended additional Action Item 7 based on the arguments outlined above, PacifiCorp reiterates its views on the handling of Class 3 DSM in the IRP. The Company has experienced inconsistent and unpredictable load reduction due to price offers in the Energy Exchange program. Conducting an analysis of historical Energy Exchange costs from 2001 when prices were at their highest may result in some price elasticity relationship during extreme market conditions. However, any consistent results, if found, would be at prices well above forecasted market prices. The IRP plans resources to fill capacity needs using normal market conditions. Energy Exchange is a non-firm, tactical resource that intermittently fills short-term needs.

PacifiCorp's Suggested Commission Disposition: The Commission concurs with Staff's assessment that PacifiCorp's proposed acquisition of Class 2 DSM programs should not be capped based on the limited analysis in the IRP. The Commission agrees with Staff's proposed modification to Action Item 2 as amended by PacifiCorp: Use decrement values to assess cost-effective bids in DSM RFPs. Acquisition of 250 MWa of base Class 2 DSM and ~~200 MWa or more of~~ additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth, and as approved by each state's commission, is acknowledged.

In addition, for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp should:

- ~~Conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in its Utah service area over the IRP study period and assess how the Company's base and planned programs compare with the cost effective amounts determined in the study.~~
- Develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach.
- ~~Determine the expected load reductions from Class 3 DSM by conducting an analysis of expected load reduction due to operation of the Energy Exchange program and model the resulting price/load relationship as resource programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply side options.~~
- Assume that existing interruptible contracts will continue unless the Company for good reason believes they are not renegotiable or other resources would provide better value.

[10] The cost of a study that would potentially help guide DSM would cost in the $800,000 to $1,000,000 range.

4. Non-Hydro Renewable Resources

The Company agrees to model wind in a manner comparable to other supply-side options for the next IRP, and to provide associated sensitivity and risk analysis of various wind capacity amounts. PacifiCorp notes that due to the zero-operating-cost assumption used for wind turbines, a common practice among utilities for IRP wind modeling is to specify an achievable maximum penetration amount in simulation models. The Company expects to use that approach to determine the upper boundary for wind quantities established for its portfolio optimization and detailed production cost modeling efforts.

PacifiCorp also agrees to refine the capacity contribution (Effective Load Carrying Capability) methodology for wind in the next IRP. With regard to investigating the effect of thermal resource type on wind resource integration, PacifiCorp proposes to investigate the relationship between portfolio composition and the cost and feasibility of integrating wind resources. The wording in Action Item 3 appears to imply that certain portfolios may preclude or unduly limit the ability to integrate wind. The primary mechanism for limiting the ability to integrate wind is expected to be cost, not physical ability to take the power into the system.

Finally, with respect to executing an agreement with the Energy Trust of Oregon to reserve funds for renewable resource projects, PacifiCorp agrees to execute such an agreement to set aside ETO funding to support PacifiCorp's acquisition of renewables. The Company expects the agreement to define the period of time over which PacifiCorp can use the available funding, after which such funding may be redistributed to other ETO programs. The agreement would also define locational requirements for projects that receive ETO funding.

PacifiCorp's Suggested Commission Disposition: We note that the Company has reached agreement to acquire only one renewable resource project, and that it did not meet its 2005 target of 100 MW. Further, we acknowledged PacifiCorp's 2003 IRP with the agreed-upon modification to the Action Plan that the Company would acquire renewable resources sooner than the yearly targets if economic to do so. Given the level of bids the Company shows in the IRP as potentially economic, we would expect the Company ~~might have exceeded, rather than fallen short of,~~ to have at least met its early target.

The Commission agrees with RNP that the Company should devote sufficient resources to reach its renewable resources targets. The Commission declines, however, to direct how PacifiCorp should allocate resources, as RNP recommends.

PacifiCorp has cited the delay in renewing the federal production tax credit, and its short extension, as one of the problems affecting its acquisition of renewable resources. We therefore agree with Staff that the Company should execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable the Company to complete resource agreements quickly upon extension of the federal production tax credit.

In addition, for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp should analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's cost ~~ability~~ to integrate wind resources.

5. Potential CO_2 Regulatory Costs

PacifiCorp commends Staff on their stance towards the Company's determination and use of its own base-case CO_2 regulatory cost assumptions. As stated in the IRP and the "Response to Oregon Party Comments" document, PacifiCorp believes that the risk of higher costs under a potential CO_2 regulatory framework justifies inclusion of a CO_2 adder as a base case modeling assumption. Barring a change to state IRP policies and procedures or the emergence of a broad consensus on the likely timing and magnitude of a CO_2 regulatory cost structure, modeling high cost allowance levels is appropriately conducted as part of scenario analysis for the next IRP.

6. Coal Plant

PacifiCorp disagrees with Staff's conclusions regarding the need for a coal plant by the summer of 2011. Staff's comments addressed the need for a resource in the timeframe identified and the selection of the coal plant as the least cost resource for that timeframe. PacifiCorp provides comments with regards to Staff's conclusions and proposed modifications to the recommendations.

Need for the Resource

Staff's arguments that a thermal plant is not needed by the summer of 2011 are based on their conclusions regarding Planning Margin, use of Class 3 DSM as a reliable resource, and extension of expiring interruptible contracts throughout the study period. PacifiCorp understands Staff's hesitancy toward committing to a long-term resource (i.e. coal resource). However, PacifiCorp has an obligation to serve load and does not think it is prudent to rely on reductions in Planning Margin and/or use of Class 3 DSM to realize a one-year deferral of a needed supply-side resource, much less to eliminate the need for such a resource.

Staff quotes its estimation that a 12% Planning Margin is appropriate as a reason for not acknowledging the CY 2011 resource. This is a selective inconsistency, since moving to a 12% Planning Margin should also delay the CY 2009 resource and potentially affect the timing of other action items, yet Staff makes no mention of this fact. This inconsistent application by Staff of the effects of reducing the reserve Planning Margin suggests that a goal of trying to reduce the reserve margin is to prevent construction of the least cost resource in CY 2011—a coal plant.

PacifiCorp does believe there is a need for a resource in the FY 2011 timeframe; however transmission could be an alternative to bridging the gap between loads and resource either in the short or long term. As part of their comments, Staff stressed the importance of transmission as part of the resource portfolio. PacifiCorp realizes that targeted transmission expansion opportunities could provide flexibility to deliver additional power from existing resources, procurement of power with shorter-term commitments, or access to low cost resources in remote locations (i.e. Powder River Basin Coal, wind, or both). The flexibility associated with these types of transmission expansion opportunities could postpone the need for acquiring a long-term, supply side resource close to the load center. PacifiCorp is committed to evaluating transmission alternatives and pursuing those alternatives that appear to be cost-effective.

Coal Plant Delay Scenario
Regarding the response to the coal plant delay scenario data request to which Staff refers to in their comments, the data request asked PacifiCorp to evaluate the plant deferral for the Preferred Portfolio, not Portfolio E as indicated in Staff comments. Therefore, Staff's stochastic results comparison with Portfolio E results is not appropriate; PacifiCorp conducted the deferral runs using the Preferred Portfolio which had a lower PVRR than Portfolio E. The correct comparison would be with stochastic results for the original Preferred Portfolio, which PacifiCorp did not perform. If that comparison was made, then it would show that deferring a coal plant would increase stochastic upper-tail cost. Of course, deferring any large resource will lower deterministic PVRR.

Unserved Energy Comparison and Class 3 DSM
With regard to Staff's comparison of expected unserved energy to the levels of reductions that PacifiCorp realized in some of its Class 3 DSM programs, these types of customer voluntary load reduction programs, whether a payment is offered or not, cannot reliably result in load reduction and, therefore, cannot replace energy not served.

The Energy Exchange program does not provide consistent or predictable load reduction capabilities based on actual program experience. Based on the Company's actual experience, some days when prices are offered, even prices over $90/MWh, there is no response from customers. The Company cannot rely on load reduction from customers in this program.

The 20/20 program that was operated in the summer of 2001 was conducted under unique circumstances. There was wide publicity regarding energy shortages and rotating outages in California during this time period. The company's offer for customers to reduce load was made in the midst of this "energy crisis" in the west. This situation does not exist today and is not reasonably expected to exist during the planning period given the ramifications of the "energy crisis" and regional focus on capacity adequacy. Customer attention to energy issues is lower. The "threat of energy shortages" is not in the daily news. This lack of urgency would greatly reduce any customer response to any program of this type. In support of this point, we have been operating our Power Forward Program during the summer months in Utah since 2001. This "stop light" program sends out media alerts regarding the need for customer conservation efforts the following day. Green alerts call for normal conservation efforts. Yellow alerts, which are based on a temperature and market price trigger, call for intensified conservation efforts. Red alerts warn of impending shortages if intensive load reduction efforts are not made. These are precipitated by a NERC 1 Alert. Our experience in this program is that we can sometimes get customer load reductions for one or two days, however, the third day load reduction diminishes greatly. In addition, the load reduction when a yellow alert is called for is neither consistent nor predictable.

Coal Plant Selection

After discussing the need for the new resource, Staff questions the selection of a coal plant as the least cost alternative for the CY 2011 resource. Staff's conclusions regarding the coal plant are based on a review of the all gas portfolio, long lead time of coal resources, load forecast scenario data request results, and evaluation of CO_2 risks.

Evaluation of Portfolio M
Staff mentions that Portfolio M, which contains all gas units, has the lowest deterministic PVRR of all portfolios evaluated. This is true for the base case analysis; however, PacifiCorp indicates on page 160 of the IRP, that "Since the base gas forecast was developed in June 2004, (gas) prices have increased." PacifiCorp performed a scenario analysis using the most recent gas price forecast, which resulted in Portfolio M moving from first among the rankings to sixth out of the six portfolios that were tested for this scenario.

Long Lead Time for Coal Resources
PacifiCorp agrees with Staff's assessment of a coal plant being a long lead time resource. This is precisely why PacifiCorp indicated in its response to intervenor comments that the Company should take prompt and focused steps to address the growing gap between its obligations and resources by procuring the lowest cost resources. The Supply Side Options table (Table C.28) in the Technical Appendix shows that the Total Resource Cost of the proxy coal plant modeled in 2011 is \$36/MWh, as compared to a proxy gas plant's Total Resource Cost of approximately \$54/MWh. Therefore, based on the results of the deterministic and stochastic analysis and the above-mentioned Total Resource Cost analysis, PacifiCorp continues to believe the lowest cost resource for this time period is a coal plant.

Load Forecast Scenario
Staff pointed out that Portfolio E performed poorly in the requested scenario analysis where loads were decreased (two standard deviations lower than forecasted). What Staff fails to mention is that the portfolio that performs the best under this scenario is Portfolio Q, which actually has two coal proxy resources instead of the one coal plant in Portfolio E. PacifiCorp also emphasized in the Load Forecast section above that a load growth scenario analysis that does not account for correlations with gas and electricity prices is inferior to a stochastic analysis that does account for such correlations.

CO_2 Risk
PacifiCorp continues to believe that it is a prudent practice to use a carbon adder as a base case assumption. Doing so goes beyond what is required by Commission guidelines which require only sensitivity runs using an adder. As suggested in our earlier comments, the Company shows that current regulatory developments strongly support a base case adder in the \$8/ton range. Staff has indicated that PacifiCorp should continue to use its own base-case assumptions in this regard. PacifiCorp points out that Staff claims that the Company does not sufficiently weigh the risk of potentially extreme CO_2 regulatory costs in its resource decisions, which appears to

contradict Staff's position on the use of base-case assumptions. If the adder becomes merely a tool for stakeholders to use to push the IRP planning process towards a specific outcome then it may no longer be a valuable and prudent approach to evaluating carbon risk. PacifiCorp notes that other intervenors reviewing the IRP suggest the Company has selected an adder that is too high and therefore biased the results towards gas and away from coal.

IGCC

PacifiCorp supports Staff's recommendation to continue to evaluate and investigate IGCC in the next IRP. PacifiCorp has already commissioned a detailed study of this resource to determine the viability of the technology.

Staffs Recommendations

Based on the arguments outlined above PacifiCorp *can not* agree with the following Staff recommendations:

- Not acknowledge Action Item 8, acquisition of a 600 MW high capacity factor resource on the East side of the system by CY 2011
- Explicitly not acknowledge a new coal unit by CY 2011

PacifiCorp's Suggested Commission Disposition: <u>The Commission needs further evidence to support the addition of a coal plant in the CY 2011 time frame. Therefore, before PacifiCorp makes a final decision to procure a coal plant it should either file a Resource Rate Plan under ORS 757.212 or address the resource consistent with the guidelines from the final commission order in Docket UM 1182. As an alternative to procuring coal in the CY 2011 time frame, the Company should evaluate transmission expansion alternatives to bridge the gap before large resource decisions can be agreed.</u> ~~The Commission is not convinced that PacifiCorp's IRP makes the case for a second large thermal resource on the East side of the system by CY 2011. We rely particularly on comments regarding Planning Margin, omission of interruptible contracts, incomplete analysis of DSM opportunities and shortcomings in comparing DSM resources on par with supply side options, failure to reexamine the potential risk reduction benefits of renewable resources above the 2003 IRP target under updated assumptions, and cost savings of the coal plant delay scenarios coupled with reasonable measures that could be taken to avoid outages, including additional short-term purchases, wind resources and DSM programs, as well as acquisition of distributed resources. Therefore, the Commission does not acknowledge construction of a 600 MW high capacity factor resource in or delivered to Utah by CY 2011.~~

~~Further, the Commission explicitly does not acknowledge acquisition of a new coal plant at this time. Portfolio M, the all natural gas portfolio, is less costly than PacifiCorp's preferred Portfolio E under the Company's base case assumptions. The average all-in stochastic cost for all gas Portfolio M is 2.5% more than PacifiCorp's preferred Portfolio E, but Portfolio M performs better under all CO2 scenarios tested except a zero adder. We find that there is considerable risk to ratepayers of CO2 regulatory costs significantly exceeding PacifiCorp's base case assumption of $8.38/ton (2010$), and that those risks could well exceed the estimated risk reduction benefits of Portfolio E compared to Portfolio M attributable to gas price volatility. We also note the poor performance of Portfolio E under a scenario with significantly lower load growth than forecasted.~~

~~In addition, the Commission does not find that PacifiCorp made the case that a coal plant is in the long run public interest in light of mounting scientific evidence about the likely effects of CO2 emissions on climate, the potential carbon allowances that might be required to avoid catastrophic impacts, and the momentum building toward regulatory action to limit CO2 emissions.~~

7. Hydropower Resources

PacifiCorp agrees with Staff's recommendation to analyze environmental impacts of pumped storage technology if it becomes a viable resource for future IRPs. However, the Company disagrees with Staff's view that the Company should commit, during the IRP process or otherwise, to considering potential customer cost and risk benefits of dam removal when considering relicensing alternatives. Under the Federal Power Act, licensees are required to undertake analyses of the costs, benefits and environmental impacts of the project as part of obtaining a new generating license. This must be done in consultation with state and federal agencies, tribes and other governmental organizations. However, in undertaking these evaluations, there is no requirement per se to conduct dam removal or decommissioning studies. Licensees may voluntarily choose to examine project decommissioning during this process, or FERC, as part of its environmental analysis responsibilities, may request such information in order to determine whether or not decommissioning is a "reasonable" alternative.

PacifiCorp also clarifies that, while supporting the Federal Power Act hydroelectric licensing language contained in the comprehensive energy bill currently being debated by Congress, the Company was not proposing or sponsoring the legislation as indicated in Staff's discussion on page 47 of the Draft Proposed Order.

PacifiCorp's Suggested Commission Disposition: If pumped storage technology becomes a viable resource option in the future, the Commission expects PacifiCorp to analyze the associated environmental costs that ratepayers might incur. ~~We also expect PacifiCorp to consider the potential cost and risk benefits for customers of dam removal when it is considering relicensing alternatives.~~

8. Distributed Generation

PacifiCorp disagrees with Staff that the lack of CHP scenario modeling in IRPs represents a regulatory barrier to increased use of distributed generation. CHP modeling can be conducted with any theoretical amount of CHP in portfolios. The issue is forecasting a feasible and dependable amount of CHP capacity suitable for long term resource planning. As already noted by PacifiCorp, CHP projects are rarely dispatchable and thus do not contribute to peak capacity resource needs. They typically provide energy only to the system on a long term planning basis. Customer economics, assessment of risk, and desire to enter the energy business are major factors in the decision by the customer to install a CHP system. PacifiCorp cannot predict these types of customer actions on a long-term basis. Relying on projects that are brought on line and removed from service based on customer economics makes projecting realistic CHP resource opportunities a risk to maintaining targeted planning reserve margins.

Staff also recommended analyzing the potential for distribution asset deferral as part of the CHP evaluation in the next IRP. Distribution planning is beyond the current scope of an IRP, and is one of the issues being considered under the UM 1056 docket (Issue 11: "Should transmission and distribution investments/costs and opportunities be incorporated into integrated resource planning?").

PacifiCorp's Suggested Commission Disposition: Staff's recommended action on CHP for the next IRP is beyond the scope of the Commission's acknowledgement review. In addition, the actions cited in Staff's additional Action Item 11 are issues currently pending in UM 1056. Therefore, the Commission rejects Staff's additional Action Item 11.
~~Among the ways the Commission plans to encourage utilities and customers to meet energy needs at the lowest possible cost and risk is to remove regulatory barriers to the use of distributed generation. The Commission views inadequate modeling of distributed resources in utility IRPs as one of these barriers.~~

~~For the next IRP or Action Plan brought forward for the Commission's consideration, PacifiCorp should include in its portfolio modeling high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load growth areas to evaluate the potential for reducing costs and risks of generation and transmission. Further, the Company should include in its modeling the value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.~~

9. Transmission

PacifiCorp agrees that additional analysis could be done to address the relative costs and risks of transmission investments that enable access to shorter-term market purchases or lower-cost generation alternatives. Such analysis would be consistent with PacifiCorp's goal of improving transmission resource modeling and integrating transmission project initiatives into the resource planning process as discussed in the IRP Action Plan (see page 188 of the IRP).

10. Suggested Modifications to Conclusions

This section presents PacifiCorp's suggested modifications to Staff's proposed conclusion section on pages 54-56 of the Draft Order.

~~Exception:~~ Revised Action Item:

The need for a resource in or delivered to Utah by the summer of 2011 is acknowledged, but not a specific resource size, type of unit, or procurement date. Prior to the selection of a coal plant as the preferred resource for the 2011 time period, PacifiCorp will file a Resource Rate Plan under

ORS 757.212 or address the resource consistent with the guidelines from the final commission order in Docket UM 1182. PacifiCorp will evaluate transmission alternatives to fill the need in this time period (Implementation Action 8). ~~Action Item 8, Procure a 600 MW high capacity factor resource in or delivered to Utah by the summer of 2011, is not acknowledged, including acquisition of a new coal unit.~~

Modifications

Revised Action Item

1. Use decrement values to assess cost-effective bids in DSM RFP(s). Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth, and as approved by each State's Commission. (Action Item 2)

Additional Action Items

2. Execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable timely completion of ~~power purchase~~ resource agreements upon extension of the federal production tax credit.

3. For the next IRP or Action Plan, analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's cost ~~ability~~ to integrate wind resources.

4. For the next IRP or Action Plan, develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach.

5. For the next IRP or Action Plan, assume existing interruptible contracts continue unless they are not renegotiable or other resources would provide better value.

6. For the next IRP or Action Plan, assess IGCC technology in a location potentially suitable for CO_2 sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties including market prices and CO_2 regulation.

7. For the next IRP or Action Plan, analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission.

Conditions

~~1. For the next IRP or Action Plan, conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in PacifiCorp's service area over the IRP study period and assess how the company's base and planned programs compare with the cost effective amounts determined in the study.~~

~~2. For the next IRP or Action Plan, determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio conduct an analysis of expected load reduction due to operation of the Energy Exchange program and model the resulting price/load relationship as resource options that compete with supply side options.~~

~~3. For the next IRP or Action Plan, analyze Planning Margin cost risk tradeoffs within stochastic modeling of portfolios. If feasible, analyze the cost risk tradeoff of all portfolios at various Planning Margins. If not feasible, build all portfolios to a set Planning Margin, test them stochastically, and adjust top performing portfolios to higher and lower Planning Margins for further stochastic evaluation. Evaluate loss of load probability, expected unserved energy and worst case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Evaluate alternatives for determining the expected annual peak demand for determining the Planning Margin — for example, planning to the average of the eight hour super peak period.~~

~~4. For the next IRP or Action Plan, evaluate within portfolio modeling the potential for reducing costs and risks of generation and transmission by including high efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load growth areas. Evaluate the potential value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.~~

Response to Staff's Draft Proposed Order on PacifiCorp's Integrated Resource Plan

(Docket No. LC 39)

INTRODUCTION

On June 27, 2005, pursuant to the March 21, 2005 Prehearing Conference Memorandum, Oregon Public Utility Commission Staff (Staff) filed its Comments and Recommendations (Staff Comments) on PacifiCorp's 2004 Integrated Resource Plan (2004 IRP) and a Draft Proposed Order (Draft Order). PacifiCorp hereby files these comments and recommendations in reply to the Staff Comments and Draft Order.

SUMMARY OF COMMENTS AND RECOMMENDATIONS

PacifiCorp appreciates the collaborative and informal nature of Oregon's IRP process and the helpful role that Oregon Commission Staff plays in shaping the IRP in the public process. However, the Company notes that the positions in Staff's Comments and Draft Order on PacifiCorp's Planning Margin, the CY 2011 resource, and other issues were raised after the conclusion of the public input process rather than during the year-long process. In the Company's view, one purpose of the public planning process is to allow all parties to discuss recommendations such as those presented in Staff's Comments and Draft Order to enable parties the opportunity to develop a consensus and provide the Company with time to consider the merits of the recommendations in the final plan. Given the multi-state nature of PacifiCorp's IRP, a full airing of issues in the IRP public planning process is particularly important.

In the spirit of collaboration, , PacifiCorp has stipulated to many of the changes Staff proposes to PacifiCorp's IRP and Action Plan, including Staff's proposed additional Action Item 1 (increased DSM), additional Action Item 2 (ETO agreement), additional Action 3 (expanded renewables modeling), additional Action Item 5 (DSM modeling), additional Action Item 6 (modeling interruptible contracts), additional Action Item 8 (IGCC assessment), and additional Action Item 10 (transmission modeling).

Because PacifiCorp relies heavily upon its IRP, the nature and form of the Commission's acknowledgment of its IRP is critical to PacifiCorp. For this reason, on the following points implicating fundamental building blocks of PacifiCorp's IRP—including principles currently at issue before the Commission in UM 1056—PacifiCorp cannot agree to Staff's position: (1) Staff's recommendation against acknowledgement of a second large thermal resource, including a coal plant by the summer of 2011; (2) Staff's additional Action Item 4 (DSM study); (3) Staff's additional Action Item 7 (modeling Class 3 DSM); (4) Staff's additional Action Item 9 (modeling Planning Margin cost-risk tradeoffs and evaluating Class 3 DSM for meeting unserved energy); (5) Staff's additional Action Item 11 (scenario modeling of Combined Heat and Power).

PacifiCorp respectfully submits that these recommendations exceed the appropriate scope of an acknowledgement proceeding, prejudge issues currently pending in UM 1056, and are unsupported by the weight of the credible information and analysis available in this proceeding. For these reasons, PacifiCorp requests that the Commission reject Staff's proposed recommendations and instead issue an order acknowledging the 2004 IRP and Action Plan as outlined below.

1. Staff's Proposed Recommendations Exceed the Proper Scope of Commission Review in an Acknowledgement Proceeding.

In Staff's Comments, Staff recommended that the Commission acknowledge the 2004 IRP—with the notable exception of the 2011 thermal resource—and made 11 modifications to the Action Plan. (Staff Comments at 12.) With respect to the recommended Actions, it is important to note that only one modifies an action item actually included in PacifiCorp's Action Plan. The other 10 recommended Implementation Actions add new actions to the Action Plan. Of those 10 additional implementation actions, only one relates to the current Action Plan. The remaining 9 modifications all relate to the next IRP or Action Plan (each begin with the following phrase, "For the next IRP or Action Plan . . .") and require PacifiCorp to undertake some different or additional analysis in that next cycle regardless of input received from other stakeholders. (*Id.* at 13-14.) Staff recommends that the Commission require the recommendations be "conditions for acknowledgment". (*Id.* at 14). As noted above, in the interest of compromise and collaboration, PacifiCorp has agreed to the majority of these recommendations.

With respect to the proposed additional Action Items 4, 7, 9 and 11, PacifiCorp submits that conditioning acknowledgment of this 2004 IRP on what PacifiCorp must do after the public input and process for the next IRP is beyond the proper scope of an acknowledgment proceeding.[1] In the Commission's Least Cost Planning Order (No. 89-507)[2], the Commission adopted a planning requirement for all utilities. *Re Least-cost Planning for Resource Acquisitions*, Docket UM 180, Order 89-507 (OR PUC April 20, 1989). The approach was designed to provide a "thorough" yet "flexible" approach to utility planning and provide an opportunity for public input in the planning process "at its earliest stages." *Id.* The result of the IRP process is to be "the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs." *Id.*

[1] PacifiCorp acknowledges that some of the agreed-upon, Staff-recommended modifications also are based on conditioning approval of this IRP on requirements for the next IRP. Nevertheless, PacifiCorp has agreed to these recommended modifications and not the others because the agreed-to modifications do not implicate the key policy considerations that PacifiCorp does not agree with. Those policy considerations are discussed in the next section of these comments.

[2] Order 89-507 is still good law in Oregon controlling IRP procedural and substantive requirements. While the Order is being reviewed in Docket No. UM 1056, it has never been overturned or rejected outright by this Commission.

The Commission laid out six procedural and four substantive requirements that are to be observed by utilities in the planning process. *Id.* Utilities were directed to file plans every two years which would be reviewed by the Commission for "adherence to the principles enunciated in [Order 89-507] and subsequent orders." *Id.* This review was intended to result in an "acknowledgement" order. *Id.* The Commission defined "acknowledgment" as follows: "Acknowledgment of a plan means only that the plan *seems reasonable* to the Commission *at the time the acknowledgment is given*." (*Id.* (Emphasis added.))

The Commission's Order 89-507 provided a framework for proceeding with plans that as filed could not be acknowledged: "If further work on the plan is needed, the Commission will return it to the utility with comments. This process should eventually lead to the acknowledgment of the plan." In a later order, the Commission clarified that in an acknowledgment decision it was stating "its opinion about what resource strategies or actions are reasonable" in order to "provide clear guidance to the company." *Re Portland General Electric*, Docket LC 2, Order No. 91-1552 (Or. PUC Nov. 8, 1991). In providing this guidance, the Commission made clear that it can either "return a plan for further work or acknowledge the plan with modifications included to make the plan reasonable."[3] *Id.* The Commission also stated that it considers comments from all parties in reaching its final determination on acknowledgment. PacifiCorp has relied upon these existing OPUC guidelines and has conducted its IRP process in accordance with the defined requirements.

Staff's proposal to condition acknowledgment of this 2004 IRP on addition of items to the current Action Plan that would require untried, potentially controversial analysis to be conducted in the next IRP is inconsistent with this acknowledgment framework. The 2004 IRP should be judged a reasonable plan (with or without modifications to the plan) given what is known and knowable *at this time*. PacifiCorp concedes that Order 89-507 contemplates that the requirements for planning may evolve over time and be supplemented by subsequent orders. Indeed, the Commission has in previous acknowledgment orders ordered the utility (and at times, other parties) to engage in processes to better analyze certain issues before and during the next IRP cycle. This is the inherent benefit of the flexibility of Order 89-507 recognized by the Commission at the time. However, while the analysis process can and should evolve over time, the consideration and determination of what is a reasonable plan at this time should not be dependent on that further analysis. Instead, the Commission's order contemplates that the Commission will look to the analysis and information available in this IRP cycle from all parties and determine if the plan "seems reasonable." (Order 89-507.)

The Commission's later orders in least-cost planning filings by PacifiCorp and other utilities confirm this interpretation of Order 89-507. This Commission has not heretofore conditioned acknowledgment of one IRP on Staff's recommendation to include action items in that IRP for

[3] The Commission acknowledged that its proposed "modifications" are not mandatory obligations of the utility. For example, the Commission recommended certain actions for utility near-term conservation activities in LC 2. In doing so, the Commission stated that it "recognizes that [the utility] is not required to comply with these recommendations." Rather, utility management still bears the ultimate responsibility as to resource decision. If the utility's decisions are consistent with the acknowledgment order, then the utility "may face a greater likelihood that its actions will be judged prudent and the costs allowed in a future rate case." If the utility chooses to take actions inconsistent with the order, it must be prepared to explain why it has taken those actions.

the next IRP over the utility's objection[4]. Instead, where parties offer suggestions for improvement in the IRP analysis, the Commission has either ordered PacifiCorp (or other utilities) to study the issue and report back to Staff and the Commission[5] or where the record is clear as to the need for the additional analysis, the Commission has simply ordered the utility to undertake the analysis in the next cycle.[6]

Staff has previously recognized the distinction between modifications proposed to make the current IRP reasonable and those suggestions proposed to improve the next planning cycle. For example, in LC 6, PacifiCorp's second integrated resource plan filing, Staff made 23 separate recommendations on the IRP and Action Plan.[7] The first 11 modifications proposed changes to the current Action plan. The next 10 suggested steps for PacifiCorp to undertake in performing future resource planning activities and the final two recommended non-acknowledgment of two aspects of the plan. In its order, the Commission adopted modifications to the then-current Action Plan and with those modifications acknowledged the plan. The Commission also ordered PacifiCorp to undertake certain but not all of Staff's proposed steps for the next planning cycle. The Commission's ultimate order recognized the distinction between taking action on the plan then under review and adopting proposals for making the next cycle better: "RAMPP-2 should be acknowledged with the modifications to the Action Plan adopted above. In addition, PacifiCorp should undertake the other actions discussed above in preparing * * * its next integrated resource plan."[8] While both types of proposals (modifications to current plan and recommendations for future plans) are properly within the purview of the Commission's IRP review, there is no reasonable basis for linking the two.

PacifiCorp respectfully submits that the Staff Comments which propose that the Commission condition acknowledgment of 2004 IRP on adding additional action items related to the next IRP cycle are beyond the scope of the Commission's acknowledgement review as laid out in its

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[4] Staff has previously recommended that the Commission acknowledge a utility's plan subject to modifications that included adding action items into the current plan which dictate how the Company would approach planning in the next cycle. However, it appears that while the Commission has adopted such modifications, it has done so only where the utility has agreed to the modifications. *See, e.g., Re Pacific Power & Light Co.,* Docket LC 1, Order No. 90-1658 (OR PUC Nov. 9, 1990) (utility agreed to all Staff's recommendations), *Re Portland General Elec. Co.*, Docket LC 2, Order No. 91-1552 (OR PUC Nov. 8, 1991) (utility disagreed with some recommendations but those did not involve changing current action plan to require certain analysis in the next IRP cycle); *Re Northwest Natural Gas Co.*, Docket LC 3, Order 91-822 (OR PUC July 1, 1991) (utility agreed to all staff recommendations) .

[5] For example, in PacifiCorp's first least cost planning filing with the Commission in Docket LC 1, a party recommended that a CO_2 adder be included in resource costs. PacifiCorp tested an adder with a different value and developed a scenario to reduce CO_2 emissions. *See Re Pacific Power & Light Co.*, Docket LC 1, Order No. 90-1658 (OR PUC Nov. 9, 1990). Staff found that PacifiCorp's treatment of external costs was a "reasonable first effort." *Id.* Rather than requiring additional analysis prior to issuing an order acknowledging the IRP, the Commission reached the same conclusion as Staff—for purposes of that IRP, PacifiCorp's analysis was "reasonable". *Id.* However, the Commission directed Staff to recommend a process for investigating the issues related to externalities. *Id. See also Re Cascade Natural Gas Corp.*, Docket LC 20, Order No. 98-104 (OR PUC March 16, 1998); *Re Northwest Natural Gas Co.*, Docket LC 29, Order No. 00-782 (OR PUC Dec. 11, 2000); *Re Idaho Power Co.*, LC 32, Order No. 03-389 (OR PUC July 3, 2003).

[6] *See e.g., Re PacifiCorp*, Docket LC 31, Order No. 03-508 (OR PUC Aug. 25, 2003) (ordering PacifiCorp to develop, with public input, a methodology for determining an appropriate capacity value for wind resources).

[7] *See Re PacifiCorp*, Docket LC 6, Order No. 93-206 (OR PUC Feb. 12, 1993); *See also Re Portland General Elec. Co.*, LC 7, Order No. 93-804 (OR PUC June 11, 1992).

[8] *See Re PacifiCorp*, Docket LC 6, Order No. 93-206 (OR PUC Feb. 12, 1993).

guidelines. While the Commission can appropriately order PacifiCorp to consider additional analyses in its next cycle as a refinement on Order 89-507, it should not, contrary to its own precedent upon which PacifiCorp has relied in preparing this IRP, confuse those future refinements in the process with the determination of the reasonableness of the IRP currently before it. For those reasons, PacifiCorp requests that the Commission reject Staff's additional Action Items 4, 7, 9 and 11.

2. The Commission Should Not Prejudge Issues Currently Pending Before It in Another Commission Proceeding Prior to Hearing From All Parties on Those Issues.

Staff's additional Action Items 4, 7, 9 and 11 raise an additional concern which justifies Commission rejection of these changes at this time. These issues are squarely before the Commission in another proceeding, UM 1056. It is inappropriate for Staff to condition acknowledgment of the 2004 IRP on unresolved but pending issues in another docket. Because these issues are pending in UM 1056, the Commission should not adopt these recommended modifications even as refinements in the planning process at this time.

The Commission opened Docket UM 1056 in December of 2003 in order to "reconsider the fit between traditional least cost planning and a competitive industry, and to reopen an investigation to review least cost planning requirements."[9] The docket was suspended until a final order was issued in Docket UM 1066. Activity resumed in the docket early this year after the UM 1066 order was issued. Joint issues list in UM 1056 were filed by the parties on April 21, 2005. This Commission adopted the joint issues list by Memorandum issued June 6, 2005.

Staff's recommended Additional Action Items 4, 7, 9 and 11 fall squarely into issues included on the Commission-approved issues list in UM 1056. Specifically, Staff recommended additional Action Item 4 requires PacifiCorp to conduct an economic analysis of achievable Class 1 and Class 2 DSM measures and compare the Company's base and planned programs with the cost-effective amounts determined in the study. Staff's recommended additional Action Item 7 requires PacifiCorp to determine expected load reductions associated with Energy Exchange and interruptible contracts at various prices and model them as Class 3 DSM resources competing with other supply side options. These two recommended Implementation Actions fall squarely into Issues 13 and 14 on the UM 1056 approved issues list: "How should cost-effective conservation be analyzed and included in resource planning? Should a conservation potential study be conducted and if so, how?" and "How should demand response be explicitly included in integrated resource planning on par with other options for meeting energy and capacity needs?"

Likewise, Staff additional Action Item 9, dealing with Planning Margins, is squarely before the Commission in UM 1056 under Issue 21: "How should the resource Planning Margin be determined to ensure resource adequacy and consider cost?" Since Staff recommends the use of stochastic analysis for assessing Planning Margin levels, Issue 3 is also relevant: "How should

[9] *In the Matter of the Investigation into Integrated Resource Planning Requirements,* Docket UM 1056, Order 02-546 (OR PUC Aug. 8, 2002).

integrated resource plans measure and consider the cost-stochastic risk tradeoff between candidate resource portfolios?" Finally, recommended additional Action Item 11, dealing with CHP and aggregated dispatchable customer standby generation will be addressed in UM 1056 under Issue 20: "How should distributed generation be addressed in integrated resource planning?"

The wording of the issues on the UM 1056 approved issues list leaves open for party comment and Commission consideration whether certain items should be considered and modeled in IRPs and if so, how that modeling and analysis should be conducted. Staff's recommended modifications predetermine the outcome of these issues in at least two respects. First, by including additional Action Items 4, 7, 9 and 11 as conditions to acknowledgment of this 2004 IRP, Staff effectively predetermines that these issues can and should be considered in the next IRP. Second, Staff has proposed with some specificity the parameters of the analysis of these issues in its suggestions included in the recommended modifications. If adopted, these recommended modifications would therefore also predetermine how best to model and analyze these issues.

Accordingly, if the Commission were to choose to adopt Staff's recommended Implementation Actions, it would be tantamount to predetermining the outcome in UM 1056 on these issues prior to hearing from all parties. In addition, even if the Commission were inclined to address those issues in this docket, it is premature to reach a decision on these issues. Currently, as discussed in detail below, PacifiCorp does not agree that these recommended Implementation Actions are appropriate as written. However, while parties in the UM 1056 docket have undertaken extensive and ongoing dialogue through the workshop process, the docket has not yet concluded and the Commission has not yet heard from all parties on these issues. Parties have another workshop scheduled and have yet to file opening and reply comments. PacifiCorp requests that the Commission reject Staff's recommended Implementation Actions on this basis and await the full exploration and presentation of those issues in Docket UM 1056.

For all the reasons discussed in the foregoing and subsequent sections, PacifiCorp requests that the Commission acknowledge PacifiCorp's 2004 IRP and Action Plan with only the modifications discussed herein and reject Staff's recommended additional Action Items 4, 7, 9 and 11. As a compromise solution, PacifiCorp proposes that the Commission's resolution of these issues in UM 1056—DSM, demand response, planning margin and CHP—be incorporated in PacifiCorp's next IRP public input process. This approach will provide PacifiCorp and its IRP stakeholders the appropriate forum with which to discuss the implementation details of the Commission's decision on these issues given the IRP's analytical objectives.

DISCUSSION AND DETAILED RECOMMENDATIONS

This section provides specific responses to Staff's comments and recommendations, as well as suggested wording changes to Staff's proposed Commission Disposition and Conclusion sections.

1. Load Forecast

Given PacifiCorp's stochastic analysis approach, PacifiCorp does not agree with Staff that using a scenario analysis that determines the performance of portfolios when load deviates significantly from projections provides added value. In the IRP, PacifiCorp outlined the advantages of the stochastic simulation approach—one of the most important being that it captures the relationships between deviations of load and deviations of other correlated factors, e.g., gas and market prices. Staff's proposed scenario analysis approach does not capture these important effects, and therefore yields results that are different from those obtained from stochastic simulation. In fact, by only considering load variability in isolation, it can yield contradictory and perhaps misleading conclusions regarding the PVRR impact of load growth on various portfolios, as evidenced by the load growth scenario results reported for Staff's data request. Given the clear value of modeling load as part of a stochastic analysis, PacifiCorp would be concerned that additional load-related scenario analysis would complicate the portfolio evaluation process rather than inform it.

PacifiCorp also reaffirms its belief that it would be imprudent to plan on any future other than the expected future given the lead time necessary to acquire certain resources. Stochastic analysis provides ample assessment of load forecast uncertainty while retaining the reasonableness of planning for one expected outcome. PacifiCorp also emphasizes that the IRP and procurement processes can adjust as required if the load forecast picture changes dramatically.

Finally, PacifiCorp continues in agreement with Staff that PacifiCorp should plan to serve the entire forecasted load in Oregon and that this issue should be revisited if the level of direct access participation increases significantly under current regulation or if a revised direct access tariff causes significant increases in the participation of the level of direct access.

PacifiCorp's Suggested Commission Disposition: The Commission expects consideration of several different futures through ~~to see worst-case~~ risk analysis in IRPs, including the risk that retail loads could vary significantly above or below forecasts in addition to other variables. Additional scenario risk analysis to evaluate load growth levels is not necessary provided PacifiCorp believes that load variability in the stochastic simulations encompasses suitably high and low extremes. ~~In addition to stochastic worst-case analysis that takes into account a number of variables, including retail load fluctuations, the Commission is interested in scenario risk analysis indicates how portfolios may perform if loads deviate significantly from projections.~~

2. Planning Reserve Margin

Staff is not convinced that the Company's 15% Planning Margin is appropriate, and strongly suggests that a 12% Planning Margin represents a better cost-risk tradeoff. Staff outlines its reasons supporting a lower Planning Margin, and makes some methodology recommendations for future IRPs. PacifiCorp addresses each of Staff's reasons below and provides additional support for PacifiCorp's 15% Planning Margin.

In the 2003 IRP process, PacifiCorp was asked by parties to perform a loss of load probability study (LOLP) to determine the appropriate Planning Margin to use for the 2004 IRP. PacifiCorp hired an external consultant, Global Energy Decisions, to perform a sophisticated LOLP study to inform the 2004 IRP. The LOLP study identified an 18% Planning Margin as the appropriate Planning Margin for PacifiCorp's system using a one day in ten year outage criterion. PacifiCorp took the study a step further by projecting the cost-risk trade off of various levels of Planning Margin based on customer's appetite for loss of load (a.k.a. the "bathtub chart"). This resulted in PacifiCorp using a 15% Planning Margin for the 2005 IRP. PacifiCorp felt this was reasonable from an operational perspective since the Planning Margin is to cover WECC Operating Requirement (6-7%), Regulating Margin (1-2%), deviations in expected load, and unplanned outages (PacifiCorp's unplanned outage rate is between 8-10%). This level of Planning Margin is also consistent with what is being used by neighboring utilities.

PacifiCorp discussed the Planning Margin study with the parties during the June 10, 2004 Public Input Meeting (PIM). The results of the cost-risk tradeoff analysis were presented during the July 27, 2004 PIM and a discussion with participants took place as to whether PacifiCorp should allow portfolios to drop below 15% in any year or maintain a minimum of 15% in every year. During the July 27, 2004 meeting, public input participants expressed no objection to PacifiCorp constructing portfolios that maintained a minimum 15% Planning Margin in every year of the plan.

PacifiCorp acknowledges that there is a tradeoff between cost and reliability within system planning. Greater system reliability often comes with increased resource need. However, maintaining a resource level that supplies a lower level of system reliability can impose unacceptable risks; the optimum balance of cost and risk lies somewhere in between both extremes.

There are no universally accepted standard criteria to determine the correct reserve Planning Margin. Existing methodologies require a degree of professional judgment and subjectivity. Many of the NERC sub-regions use a LOLP metric of 1 day in ten years to determine the reserve Planning Margin. Using this metric the Planning Margin study produced an 18% Planning Margin. The 15% Planning Margin derived from the "bathtub chart" is equal to a 2.2 days in ten years LOLP or 220% of the common planning metric—more risky, but appropriate given the study results. A 12% Planning Margin would lead to an even higher LOLP of about 5 days in ten years, or 500% of this common planning metric, a risk level too high for PacifiCorp given its obligation to serve customers with reliable, low cost power.

Staff notes that the all-in stochastic cost for the 12% stress case was only 0.2% higher compared to Portfolio E, with an upper tail PVRR (average of five worst results) just 1.2% higher, which would support a 12% Planning Margin. However the average PVRR for Portfolio E is still statistically lower than the PVRR for the 12% Planning Margin case (Figure 8.13, pg. 141). Also, the upper tail PVRR of the 18% Planning Margin is only 1.8% higher than the upper average PVRR for Portfolio E, which would support going to a more reliable 18% Planning Margin indicated in the Planning Margin study. Thus, this comparison is not helpful for supporting a specific optimal Planning Margin level, but rather highlights the point that a range of Planning Margin levels is economically similar.

Staff is skeptical of the unserved energy costs PacifiCorp used in its Planning Margin analysis, and expressed concern that the costs may be out-of-date, are not from PacifiCorp's service area, and are very high. Given the broad spectrum of unserved energy costs used in the study (from a low of $5,210 to a high of $44,910), PacifiCorp feels unserved energy costs have been adequately represented. PacifiCorp is aware of at least one utility, LG&E Energy, that used the EPRI system reliability study results in their most recent IRP for determining unserved energy cost values. This is noteworthy in that PacifiCorp has not set the precedent for using this study in an IRP context, and other utilities view the data as useful for reliability cost-risk tradeoff analysis. PacifiCorp also points out that Staff's statement that the weighted average unserved energy value ($24,000/MWh) was used to set the Planning Margin is incorrect. We noted in the IRP and again in the "Response to Oregon Party Comments" document that we applied a number of criteria to select the 15% Planning Margin level. Further, we did not rely on any specific value in the bathtub chart for the cost-risk tradeoff analysis due to the flatness of the cost curve segments that define the economic efficiency zones for the various customer classes. We merely note that 15% is representative of the bottom of the curves. (See page 222 of the IRP Technical Appendix:, "when considered on a whole, 15% is representative of the bottom of the curve for the system.")

Staff also notes that demand response programs such as interruptible contracts, energy buyback programs, and voluntary load reduction programs should be factored into the costs used. Staff further states that such programs could make a Planning Margin higher than 12% more attractive, but were not included in the Planning Margin or portfolio analyses. PacifiCorp agrees with Staff that demand response programs are helpful to reliability and may reduce the need to procure resources. However, the Company argues later in this document (Section 3, Demand Side Management) that the non-firm nature of Class 3 DSM precludes reliance on this resource for long-term system capacity and reliability planning purposes.

Staff points out that in July 2004 the Commission acknowledged for Portland General Electric's IRP a Planning Margin of 12%, consisting of 6% operating reserves as required by WECC and an additional 6% planning reserve, all under average hydro conditions. *See Re Portland General Electric Co.*, Docket LC 33, Order No. 04-375 (OR PUC July 20, 2004). PacifiCorp submits that this is a misleading comparison. Portland General Electric's (PGE) Planning Margin was derived with a different methodology. The underlying assumptions, system size, average unit size and outage rate, resource mix, and actual modeling approach used can cause differences in the resulting reserve Planning Margin.

Staff notes that the Planning Margin was determined on the basis of meeting the single peak hour of the year. Staff points to studies requested of the Company that show that planning to the average of the eight super-peak hours for the Eastern control area reduced the Planning Margin by some 200 MW in FY 2011 and FY 2012. Staff then notes that the revised obligation amount had no impact on the timing of the capacity additions in Portfolio E. PacifiCorp agrees that planning to the average of the super-peak hours would lower the apparent Company obligation and corresponding Planning Margin. However, PacifiCorp does not think it is prudent to undermine its obligation to serve by planning to a level less than its peak obligation. This strategy would transfer to PacifiCorp and its customers increased risk of adverse reliability and economic consequences. Staff does not specify how PacifiCorp should manage the additional 200 MW of load quoted if the Company should plan to a super-peak average load.

Staff advises that the Planning Margin be an analysis variable in the modeling of all portfolios. Staff asserts that the methodology used by the Northwest Planning and Conservation Council in its Fifth Power Plan to analyze the appropriate Planning Margin is superior to PacifiCorp's methodology. PacifiCorp acknowledges that, as pointed out above, there can be different approaches to LOLP methodologies used in developing Planning Margins. PacifiCorp's Planning Margin study, described in detail in appendix N, is the same methodology used by several large utilities in the WECC for developing their Planning Margins. The Company has identified no reason to use a different approach than that used in its study, an approach deemed reasonable and seen as adequate by many other stakeholders.

Staff recommends that for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp should determine the appropriate Planning Margin by analyzing the cost-risk tradeoff of various Planning Margins within stochastic modeling of portfolios, rather than as a separate analysis as in the 2004 IRP. Ideally, Staff recommends that the Company analyze the cost-risk tradeoff of all portfolios at various Planning Margins. At a minimum, Staff recommends that the Company initially build all portfolios to a set Planning Margin, test them stochastically, and adjust top-performing portfolios to higher and lower Planning Margins for further stochastic evaluation. Staff also recommends that the Company evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Reserve Planning Margin is a control area or system metric based on a LOLP study of that specific system; it is not a variable that changes with each portfolio being evaluated to meet future system needs. As such, Staff's recommendation is unnecessary. Additionally, PacifiCorp has no way to model stochastically the Planning Margin within its existing model, and is not aware of a model that can perform this type of analysis. Given that the model cannot perform the stochastic analysis on the Planning Margin, scenario analysis for informational purposes at a 12% and 18% reserve margin is appropriate.

PacifiCorp's Suggested Commission Disposition: <u>While the Commission agrees that the assumed costs to customers of unserved energy and costs for reducing it are disputable, there is no basis to judge 15% as being an unreasonable planning margin given PacifiCorp's IRP analysis and its consistency with current industry practice. The Commission expects to revisit PacifiCorp's Planning Margin analysis approach subsequent to the outcome of the UM 1056 proceeding and in light of regional adequacy standards being investigated and developed.</u>
~~PacifiCorp's IRP analysis does not satisfy that its proposed 15% Planning Margin is appropriate. The 12% Planning Margin stress-case portfolio is less costly on a deterministic basis, and its expected stochastic cost and upper tail cost are similar to Portfolio E which includes a 15% Planning Margin. The assumed costs to customers of unserved energy, and the cost for reducing it, are disputable. Moreover, the Company did not fully analyze the cost-risk tradeoff of various Planning Margins within stochastic modeling of portfolios. A planning reserve margin of 15% is not acknowledged.~~

~~For its next IRP or Action Plan, PacifiCorp should determine the appropriate Planning Margin by analyzing the cost-risk tradeoff within stochastic modeling of portfolios. In particular, the~~

~~Company should assess the cost-risk tradeoff of each portfolio at various Planning Margins, or explain why it cannot do so. In that case, the Company should at a minimum build all portfolios to a set Planning Margin, test them stochastically, and adjust top-performing portfolios to higher and lower Planning Margins for further stochastic evaluation. The Company also should evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Further, the Company should evaluate alternatives for determining the expected annual peak demand — for example, planning to the average of the eight-hour super-peak period, instead of the single peak hour of the year.~~

3. Demand Side Management

Conservation (Class 2 DSM)

PacifiCorp has committed to the acquisition of Class 2 DSM above the base case of 250 MWa based on finding cost-effective DSM opportunities. This will be accomplished through both the RFP process for new opportunities and continuing to improve the results of existing programs in the marketplace. One limitation is how much DSM each state's commission is willing to pay for. Consequently, the Company agrees to this commitment contingent on receiving approval from all state commissions. The Commission Disposition has been edited accordingly.

For the Company's historical resource plans through RAMPP 6, supply curves or "bundles" of DSM programs were modeled as potential resource options (for what we now call "Class 2" resources). Class 1 resources were not considered as resource options prior to the 2003 IRP. As part of the 2003 IRP process, several parties were encouraging PacifiCorp to improve its modeling of DSM and proposed that the Company adopt the "decrement approach" as documented by the Tellus Institute. The Company did adopt this new approach for both the 2003 and 2004 IRPs. The Company has since improved modeling of Class 1 resources because their characteristics can be modeled in a similar manner to supply-side resources.

By suggesting the Company develop supply curves for Class 2 programs and use this type of analysis in the next IRP, the Company would be taking a step backwards to the type of analysis conducted prior to the 2003 IRP. The Company is always open to improving DSM analysis; however, in consideration of the multi-state agreement to the decrement approach and the situs nature of DSM expenses, consultation with all parties needs to be considered before once again changing the DSM analysis approach. While the Company therefore agreed to the recommended new Action Item 5, it anticipates that development of the modeling approach will be a collaborative process among parties for the next IRP.

Regarding Staff's recommendation to have PacifiCorp conduct an economic analysis of achievable Class 1 and Class 2 DSM measures, the Company stresses that DSM costs are situs to each State; therefore, state commissions must decide if they see value in funding a DSM market potential study for their customers. As mentioned earlier, such considerations are properly dealt with in the context of the public input process and the UM 1056 proceeding, not this IRP docket.[10]

Price Responsive Load Reduction (Class 3 DSM)

Apart from the Company's objection to Staff's recommended additional Action Item 7 based on the arguments outlined above, PacifiCorp reiterates its views on the handling of Class 3 DSM in the IRP. The Company has experienced inconsistent and unpredictable load reduction due to price offers in the Energy Exchange program. Conducting an analysis of historical Energy Exchange costs from 2001 when prices were at their highest may result in some price elasticity relationship during extreme market conditions. However, any consistent results, if found, would be at prices well above forecasted market prices. The IRP plans resources to fill capacity needs using normal market conditions. Energy Exchange is a non-firm, tactical resource that intermittently fills short-term needs.

PacifiCorp's Suggested Commission Disposition: The Commission concurs with Staff's assessment that PacifiCorp's proposed acquisition of Class 2 DSM programs should not be capped based on the limited analysis in the IRP. The Commission agrees with Staff's proposed modification to Action Item 2 as amended by PacifiCorp: Use decrement values to assess cost-effective bids in DSM RFPs. Acquisition of 250 MWa of base Class 2 DSM and ~~200 MWa or more of~~ additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth, and as approved by each state's commission, is acknowledged.

In addition, for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp should:

- ~~Conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in its Utah service area over the IRP study period and assess how the Company's base and planned programs compare with the cost-effective amounts determined in the study.~~
- Develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach.
- ~~Determine the expected load reductions from Class 3 DSM by conducting an analysis of expected load reduction due to operation of the Energy Exchange program and model the resulting price/load relationship as resource programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply-side options.~~
- Assume that existing interruptible contracts will continue unless the Company for good reason believes they are not renegotiable or other resources would provide better value.

[10] The cost of a study that would potentially help guide DSM would cost in the $800,000 to $1,000,000 range.

4. Non-Hydro Renewable Resources

The Company agrees to model wind in a manner comparable to other supply-side options for the next IRP, and to provide associated sensitivity and risk analysis of various wind capacity amounts. PacifiCorp notes that due to the zero-operating-cost assumption used for wind turbines, a common practice among utilities for IRP wind modeling is to specify an achievable maximum penetration amount in simulation models. The Company expects to use that approach to determine the upper boundary for wind quantities established for its portfolio optimization and detailed production cost modeling efforts.

PacifiCorp also agrees to refine the capacity contribution (Effective Load Carrying Capability) methodology for wind in the next IRP. With regard to investigating the effect of thermal resource type on wind resource integration, PacifiCorp proposes to investigate the relationship between portfolio composition and the cost and feasibility of integrating wind resources. The wording in Action Item 3 appears to imply that certain portfolios may preclude or unduly limit the ability to integrate wind. The primary mechanism for limiting the ability to integrate wind is expected to be cost, not physical ability to take the power into the system.

Finally, with respect to executing an agreement with the Energy Trust of Oregon to reserve funds for renewable resource projects, PacifiCorp agrees to execute such an agreement to set aside ETO funding to support PacifiCorp's acquisition of renewables. The Company expects the agreement to define the period of time over which PacifiCorp can use the available funding, after which such funding may be redistributed to other ETO programs. The agreement would also define locational requirements for projects that receive ETO funding.

PacifiCorp's Suggested Commission Disposition: We note that the Company has reached agreement to acquire only one renewable resource project, and that it did not meet its 2005 target of 100 MW. Further, we acknowledged PacifiCorp's 2003 IRP with the agreed-upon modification to the Action Plan that the Company would acquire renewable resources sooner than the yearly targets if economic to do so. Given the level of bids the Company shows in the IRP as potentially economic, we would expect the Company ~~might have exceeded, rather than fallen short of,~~ <u>to have at least met</u> its early target.

The Commission agrees with RNP that the Company should devote sufficient resources to reach its renewable resources targets. The Commission declines, however, to direct how PacifiCorp should allocate resources, as RNP recommends.

PacifiCorp has cited the delay in renewing the federal production tax credit, and its short extension, as one of the problems affecting its acquisition of renewable resources. We therefore agree with Staff that the Company should execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable the Company to complete resource agreements quickly upon extension of the federal production tax credit.

In addition, for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp should analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's cost ~~ability~~ to integrate wind resources.

5. Potential CO_2 Regulatory Costs

PacifiCorp commends Staff on their stance towards the Company's determination and use of its own base-case CO_2 regulatory cost assumptions. As stated in the IRP and the "Response to Oregon Party Comments" document, PacifiCorp believes that the risk of higher costs under a potential CO_2 regulatory framework justifies inclusion of a CO_2 adder as a base case modeling assumption. Barring a change to state IRP policies and procedures or the emergence of a broad consensus on the likely timing and magnitude of a CO_2 regulatory cost structure, modeling high cost allowance levels is appropriately conducted as part of scenario analysis for the next IRP.

6. Coal Plant

PacifiCorp disagrees with Staff's conclusions regarding the need for a coal plant by the summer of 2011. Staff's comments addressed the need for a resource in the timeframe identified and the selection of the coal plant as the least cost resource for that timeframe. PacifiCorp provides comments with regards to Staff's conclusions and proposed modifications to the recommendations.

Need for the Resource

Staff's arguments that a thermal plant is not needed by the summer of 2011 are based on their conclusions regarding Planning Margin, use of Class 3 DSM as a reliable resource, and extension of expiring interruptible contracts throughout the study period. PacifiCorp understands Staff's hesitancy toward committing to a long-term resource (i.e. coal resource). However, PacifiCorp has an obligation to serve load and does not think it is prudent to rely on reductions in Planning Margin and/or use of Class 3 DSM to realize a one-year deferral of a needed supply-side resource, much less to eliminate the need for such a resource.

Staff quotes its estimation that a 12% Planning Margin is appropriate as a reason for not acknowledging the CY 2011 resource. This is a selective inconsistency, since moving to a 12% Planning Margin should also delay the CY 2009 resource and potentially affect the timing of other action items, yet Staff makes no mention of this fact. This inconsistent application by Staff of the effects of reducing the reserve Planning Margin suggests that a goal of trying to reduce the reserve margin is to prevent construction of the least cost resource in CY 2011—a coal plant.

PacifiCorp does believe there is a need for a resource in the FY 2011 timeframe; however transmission could be an alternative to bridging the gap between loads and resource either in the short or long term. As part of their comments, Staff stressed the importance of transmission as part of the resource portfolio. PacifiCorp realizes that targeted transmission expansion opportunities could provide flexibility to deliver additional power from existing resources, procurement of power with shorter-term commitments, or access to low cost resources in remote locations (i.e. Powder River Basin Coal, wind, or both). The flexibility associated with these types of transmission expansion opportunities could postpone the need for acquiring a long-term, supply side resource close to the load center. PacifiCorp is committed to evaluating transmission alternatives and pursuing those alternatives that appear to be cost-effective.

Coal Plant Delay Scenario
Regarding the response to the coal plant delay scenario data request to which Staff refers to in their comments, the data request asked PacifiCorp to evaluate the plant deferral for the Preferred Portfolio, not Portfolio E as indicated in Staff comments. Therefore, Staff's stochastic results comparison with Portfolio E results is not appropriate; PacifiCorp conducted the deferral runs using the Preferred Portfolio which had a lower PVRR than Portfolio E. The correct comparison would be with stochastic results for the original Preferred Portfolio, which PacifiCorp did not perform. If that comparison was made, then it would show that deferring a coal plant would increase stochastic upper-tail cost. Of course, deferring any large resource will lower deterministic PVRR.

Unserved Energy Comparison and Class 3 DSM
With regard to Staff’s comparison of expected unserved energy to the levels of reductions that PacifiCorp realized in some of its Class 3 DSM programs, these types of customer voluntary load reduction programs, whether a payment is offered or not, cannot reliably result in load reduction and, therefore, cannot replace energy not served.

The Energy Exchange program does not provide consistent or predictable load reduction capabilities based on actual program experience. Based on the Company’s actual experience, some days when prices are offered, even prices over $90/MWh, there is no response from customers. The Company cannot rely on load reduction from customers in this program.

The 20/20 program that was operated in the summer of 2001 was conducted under unique circumstances. There was wide publicity regarding energy shortages and rotating outages in California during this time period. The company's offer for customers to reduce load was made in the midst of this "energy crisis" in the west. This situation does not exist today and is not reasonably expected to exist during the planning period given the ramifications of the “energy crisis” and regional focus on capacity adequacy. Customer attention to energy issues is lower. The "threat of energy shortages" is not in the daily news. This lack of urgency would greatly reduce any customer response to any program of this type. In support of this point, we have been operating our Power Forward Program during the summer months in Utah since 2001. This "stop light" program sends out media alerts regarding the need for customer conservation efforts the following day. Green alerts call for normal conservation efforts. Yellow alerts, which are based on a temperature and market price trigger, call for intensified conservation efforts. Red alerts warn of impending shortages if intensive load reduction efforts are not made. These are precipitated by a NERC 1 Alert. Our experience in this program is that we can sometimes get customer load reductions for one or two days, however, the third day load reduction diminishes greatly. In addition, the load reduction when a yellow alert is called for is neither consistent nor predictable.

Coal Plant Selection

After discussing the need for the new resource, Staff questions the selection of a coal plant as the least cost alternative for the CY 2011 resource. Staff's conclusions regarding the coal plant are based on a review of the all gas portfolio, long lead time of coal resources, load forecast scenario data request results, and evaluation of CO_2 risks.

Evaluation of Portfolio M
Staff mentions that Portfolio M, which contains all gas units, has the lowest deterministic PVRR of all portfolios evaluated. This is true for the base case analysis; however, PacifiCorp indicates on page 160 of the IRP, that "Since the base gas forecast was developed in June 2004, (gas) prices have increased." PacifiCorp performed a scenario analysis using the most recent gas price forecast, which resulted in Portfolio M moving from first among the rankings to sixth out of the six portfolios that were tested for this scenario.

Long Lead Time for Coal Resources
PacifiCorp agrees with Staff's assessment of a coal plant being a long lead time resource. This is precisely why PacifiCorp indicated in its response to intervenor comments that the Company should take prompt and focused steps to address the growing gap between its obligations and resources by procuring the lowest cost resources. The Supply Side Options table (Table C.28) in the Technical Appendix shows that the Total Resource Cost of the proxy coal plant modeled in 2011 is $36/MWh, as compared to a proxy gas plant's Total Resource Cost of approximately $54/MWh. Therefore, based on the results of the deterministic and stochastic analysis and the above-mentioned Total Resource Cost analysis, PacifiCorp continues to believe the lowest cost resource for this time period is a coal plant.

Load Forecast Scenario
Staff pointed out that Portfolio E performed poorly in the requested scenario analysis where loads were decreased (two standard deviations lower than forecasted). What Staff fails to mention is that the portfolio that performs the best under this scenario is Portfolio Q, which actually has two coal proxy resources instead of the one coal plant in Portfolio E. PacifiCorp also emphasized in the Load Forecast section above that a load growth scenario analysis that does not account for correlations with gas and electricity prices is inferior to a stochastic analysis that does account for such correlations.

CO_2 Risk
PacifiCorp continues to believe that it is a prudent practice to use a carbon adder as a base case assumption. Doing so goes beyond what is required by Commission guidelines which require only sensitivity runs using an adder. As suggested in our earlier comments, the Company shows that current regulatory developments strongly support a base case adder in the $8/ton range. Staff has indicated that PacifiCorp should continue to use its own base-case assumptions in this regard. PacifiCorp points out that Staff claims that the Company does not sufficiently weigh the risk of potentially extreme CO_2 regulatory costs in its resource decisions, which appears to

contradict Staff's position on the use of base-case assumptions. If the adder becomes merely a tool for stakeholders to use to push the IRP planning process towards a specific outcome then it may no longer be a valuable and prudent approach to evaluating carbon risk. PacifiCorp notes that other intervenors reviewing the IRP suggest the Company has selected an adder that is too high and therefore biased the results towards gas and away from coal.

IGCC

PacifiCorp supports Staff's recommendation to continue to evaluate and investigate IGCC in the next IRP. PacifiCorp has already commissioned a detailed study of this resource to determine the viability of the technology.

Staffs Recommendations

Based on the arguments outlined above PacifiCorp *can not* agree with the following Staff recommendations:

- Not acknowledge Action Item 8, acquisition of a 600 MW high capacity factor resource on the East side of the system by CY 2011
- Explicitly not acknowledge a new coal unit by CY 2011

PacifiCorp's Suggested Commission Disposition: <u>The Commission needs further evidence to support the addition of a coal plant in the CY 2011 time frame. Therefore, before PacifiCorp makes a final decision to procure a coal plant it should either file a Resource Rate Plan under ORS 757.212 or address the resource consistent with the guidelines from the final commission order in Docket UM 1182. As an alternative to procuring coal in the CY 2011 time frame, the Company should evaluate transmission expansion alternatives to bridge the gap before large resource decisions can be agreed.</u> ~~The Commission is not convinced that PacifiCorp's IRP makes the case for a second large thermal resource on the East side of the system by CY 2011. We rely particularly on comments regarding Planning Margin, omission of interruptible contracts, incomplete analysis of DSM opportunities and shortcomings in comparing DSM resources on par with supply-side options, failure to reexamine the potential risk reduction benefits of renewable resources above the 2003 IRP target under updated assumptions, and cost savings of the coal plant delay scenarios coupled with reasonable measures that could be taken to avoid outages, including additional short-term purchases, wind resources and DSM programs, as well as acquisition of distributed resources. Therefore, the Commission does not acknowledge construction of a 600 MW high capacity factor resource in or delivered to Utah by CY 2011.~~

~~Further, the Commission explicitly does not acknowledge acquisition of a new coal plant at this time. Portfolio M, the all natural-gas portfolio, is less costly than PacifiCorp's preferred Portfolio E under the Company's base-case assumptions. The average all-in stochastic cost for all-gas Portfolio M is 2.5% more than PacifiCorp's preferred Portfolio E, but Portfolio M performs better under all CO2 scenarios tested except a zero adder. We find that there is considerable risk to ratepayers of CO2 regulatory costs significantly exceeding PacifiCorp's base-case assumption of $8.38/ton (2010$), and that those risks could well exceed the estimated risk reduction benefits of Portfolio E compared to Portfolio M attributable to gas price volatility. We also note the poor performance of Portfolio E under a scenario with significantly lower load growth than forecasted.~~

~~In addition, the Commission does not find that PacifiCorp made the case that a coal plant is in the long-run public interest in light of mounting scientific evidence about the likely effects of CO2 emissions on climate, the potential carbon allowances that might be required to avoid catastrophic impacts, and the momentum building toward regulatory action to limit CO2 emissions.~~

7. Hydropower Resources

PacifiCorp agrees with Staff's recommendation to analyze environmental impacts of pumped storage technology if it becomes a viable resource for future IRPs. However, the Company disagrees with Staff's view that the Company should commit, during the IRP process or otherwise, to considering potential customer cost and risk benefits of dam removal when considering relicensing alternatives. Under the Federal Power Act, licensees are required to undertake analyses of the costs, benefits and environmental impacts of the project as part of obtaining a new generating license. This must be done in consultation with state and federal agencies, tribes and other governmental organizations. However, in undertaking these evaluations, there is no requirement per se to conduct dam removal or decommissioning studies. Licensees may voluntarily choose to examine project decommissioning during this process, or FERC, as part of its environmental analysis responsibilities, may request such information in order to determine whether or not decommissioning is a "reasonable" alternative.

PacifiCorp also clarifies that, while supporting the Federal Power Act hydroelectric licensing language contained in the comprehensive energy bill currently being debated by Congress, the Company was not proposing or sponsoring the legislation as indicated in Staff's discussion on page 47 of the Draft Proposed Order.

PacifiCorp's Suggested Commission Disposition: If pumped storage technology becomes a viable resource option in the future, the Commission expects PacifiCorp to analyze the associated environmental costs that ratepayers might incur. ~~We also expect PacifiCorp to consider the potential cost and risk benefits for customers of dam removal when it is considering relicensing alternatives.~~

8. Distributed Generation

PacifiCorp disagrees with Staff that the lack of CHP scenario modeling in IRPs represents a regulatory barrier to increased use of distributed generation. CHP modeling can be conducted with any theoretical amount of CHP in portfolios. The issue is forecasting a feasible and dependable amount of CHP capacity suitable for long term resource planning. As already noted by PacifiCorp, CHP projects are rarely dispatchable and thus do not contribute to peak capacity resource needs. They typically provide energy only to the system on a long term planning basis. Customer economics, assessment of risk, and desire to enter the energy business are major factors in the decision by the customer to install a CHP system. PacifiCorp cannot predict these types of customer actions on a long-term basis. Relying on projects that are brought on line and removed from service based on customer economics makes projecting realistic CHP resource opportunities a risk to maintaining targeted planning reserve margins.

Staff also recommended analyzing the potential for distribution asset deferral as part of the CHP evaluation in the next IRP. Distribution planning is beyond the current scope of an IRP, and is one of the issues being considered under the UM 1056 docket (Issue 11: "Should transmission and distribution investments/costs and opportunities be incorporated into integrated resource planning?").

PacifiCorp's Suggested Commission Disposition: Staff's recommended action on CHP for the next IRP is beyond the scope of the Commission's acknowledgement review. In addition, the actions cited in Staff's additional Action Item 11 are issues currently pending in UM 1056. Therefore, the Commission rejects Staff's additional Action Item 11.
~~Among the ways the Commission plans to encourage utilities and customers to meet energy needs at the lowest possible cost and risk is to remove regulatory barriers to the use of distributed generation. The Commission views inadequate modeling of distributed resources in utility IRPs as one of these barriers.~~

~~For the next IRP or Action Plan brought forward for the Commission's consideration, PacifiCorp should include in its portfolio modeling high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas to evaluate the potential for reducing costs and risks of generation and transmission. Further, the Company should include in its modeling the value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.~~

9. Transmission

PacifiCorp agrees that additional analysis could be done to address the relative costs and risks of transmission investments that enable access to shorter-term market purchases or lower-cost generation alternatives. Such analysis would be consistent with PacifiCorp's goal of improving transmission resource modeling and integrating transmission project initiatives into the resource planning process as discussed in the IRP Action Plan (see page 188 of the IRP).

10. Suggested Modifications to Conclusions

This section presents PacifiCorp's suggested modifications to Staff's proposed conclusion section on pages 54-56 of the Draft Order.

~~Exception:~~ Revised Action Item:

The need for a resource in or delivered to Utah by the summer of 2011 is acknowledged, but not a specific resource size, type of unit, or procurement date. Prior to the selection of a coal plant as the preferred resource for the 2011 time period, PacifiCorp will file a Resource Rate Plan under

ORS 757.212 or address the resource consistent with the guidelines from the final commission order in Docket UM 1182. PacifiCorp will evaluate transmission alternatives to fill the need in this time period (Implementation Action 8). ~~Action Item 8, Procure a 600 MW high capacity factor resource in or delivered to Utah by the summer of 2011, is not acknowledged, including acquisition of a new coal unit.~~

Modifications

Revised Action Item

1. Use decrement values to assess cost-effective bids in DSM RFP(s). Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth, and as approved by each State's Commission. (Action Item 2)

Additional Action Items

2. Execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable timely completion of ~~power purchase~~ resource agreements upon extension of the federal production tax credit.

3. For the next IRP or Action Plan, analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's cost ~~ability~~ to integrate wind resources.

4. For the next IRP or Action Plan, develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach.

5. For the next IRP or Action Plan, assume existing interruptible contracts continue unless they are not renegotiable or other resources would provide better value.

6. For the next IRP or Action Plan, assess IGCC technology in a location potentially suitable for CO_2 sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties including market prices and CO_2 regulation.

7. For the next IRP or Action Plan, analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission.

Conditions

~~1. For the next IRP or Action Plan, conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in PacifiCorp's service area over the IRP study period and assess how the company's base and planned programs compare with the cost-effective amounts determined in the study.~~

~~2. For the next IRP or Action Plan, determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio conduct an analysis of expected load reduction due to operation of the Energy Exchange program and model the resulting price/load relationship as resource options that compete with supply-side options.~~

~~3. For the next IRP or Action Plan, analyze Planning Margin cost-risk tradeoffs within stochastic modeling of portfolios. If feasible, analyze the cost-risk tradeoff of all portfolios at various Planning Margins. If not feasible, build all portfolios to a set Planning Margin, test them stochastically, and adjust top performing portfolios to higher and lower Planning Margins for further stochastic evaluation. Evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Evaluate alternatives for determining the expected annual peak demand for determining the Planning Margin — for example, planning to the average of the eight-hour super-peak period.~~

~~4. For the next IRP or Action Plan, evaluate within portfolio modeling the potential for reducing costs and risks of generation and transmission by including high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas. Evaluate the potential value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.~~