- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the PacifiCorp 2006 Integrated Resource Plan	)))))	DOCKET NO. 07-2035-01 REPORT AND ORDER

ISSUED: February 6, 2008

SHORT TITLE

PacifiCorp 2007 Integrated Resource Plan

SYNOPSIS

The Commission does not acknowledge Integrated Resource Plan 2007 as it does not adequately adhere to the Standards and Guidelines for PacifiCorp. The Commission provides guidance herein to assist in the development of the next IRP.

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By The Commission:

I. INTRODUCTION

In January 2007, PacifiCorp, doing business in Utah as Rocky Mountain Power ("PacifiCorp" or "Company"), was expected to file its 2006 Integrated Resource Plan. On January 18, 2007, the Company filed a request for extension of time to file its 2006 Integrated Resource Plan to March 31, 2007. After due notice, a Technical Conference was held on May 3, 2007. On May 30, 2007, the Company filed its ninth Integrated Resource Plan ("IRP") pursuant to the IRP Standards and Guidelines ("Guidelines") adopted in Docket No. 90-2035-01, *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, Report and Order issued June 18, 1992. Errata sheets containing updated document references and corrections were filed by the Company on August 17, 2007.

Entitled "Integrated Resource Plan 2007" ("IRP 2007"), the report presents PacifiCorp's plan to supply and manage growing demand for electricity in its six-state service territory over the next 20 years. The report identifies, as its least cost plan, investment in a portfolio of power plants and power purchases, coupled with customer efficiency programs and direct-control load management. The type, timing and magnitude of resource additions are noted and an action plan is provided.

Based on its assumptions of existing generation capacity, generation plant life, length of existing purchase power contracts, transmission transfer capability, and load growth forecasts, PacifiCorp identifies a deficiency between existing resources and peak system requirements plus a 15 percent planning reserve[1] that grows from 147 megawatts in 2008 to 3,513 megawatts in 2016.[2] Assuming a 12 percent planning reserve, the deficiency grows from 791 megawatts in 2010 to 3,171 megawatts in 2016. PacifiCorp identifies the resource investment schedule for Portfolio RA 14, coupled with its transmission facilities investment schedule, as its least cost plan or “Preferred Portfolio,” to meet this deficiency.[3]

PacifiCorp bases its selection of RA 14 on its analysis of the present value of future revenue requirement (“PVRR”), load growth uncertainty, fuel and market price volatility, firm transmission transfer capability, hydro variability, customer prices, its view of states’ “preferences” regarding resource type, its view of whether the IRP could get acknowledged by all of the state commissions,[4] expectations of potential costs associated with meeting existing and potential environmental regulations, lead time required for plant construction or bidding, and resource planning decisions that are not model-driven which PacifiCorp makes in its overall corporate planning process, of which the IRP is a part.

To serve system-wide peak hour demand over the next ten years, cumulative supply additions and direct-control load management in the Preferred Portfolio range from 300 megawatts in 2007 to 4,679 megawatts in 2016: 4,074 megawatts from investment in

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[1] Planning reserve also provides for operating reserve; Chapter 4, page 80.

[2] Chapter 4, page 82. These values are the difference between the Peak Hour Obligation plus 15% planning reserve and existing resource capacity shown in Figure 4.3.

[3] The investment schedules for Portfolio RA 14 and the transmission projects are provided in IRP 2007, Chapter 7, page 184, Table 7.32, and page 186, Table 7.36, respectively.

[4] We note only Utah, Oregon and Idaho Commission’s consider the acknowledgment or acceptance of an IRP. Acknowledgment or acceptance means the plan complies with IRP requirements.

intermittent, intermediate and base load power plant; 336-660 megawatts in annual unspecified power purchases; and 104 megawatts through direct-control, load management programs.[5] By 2016, the additional resources are 87 percent generation plant (34 percent renewable energy, 32 percent gas, 19 percent coal, 2 percent combined heat and power),[6] 11 percent unspecified annual power purchases, and 2 percent direct-control load management.

Under the Guidelines, we consider whether to "acknowledge" IRP 2007. Acknowledgment of an IRP means it complies with the regulatory requirements of the planning process, but conveys no sense of regulatory approval of specific Company resource acquisition decisions. Instead, integrated resource planning is an open, public process through which all relevant supply-side and demand-side resources, and the factors influencing choice among them, are investigated in the search for the optimal set of resources to meet current and future electric service needs at the lowest total cost to the utility and its customers, in a manner consistent with the long-run public interest, given the expected combination of costs, risks and uncertainty. Clearly, PacifiCorp management retains responsibility for its decisions.

Utah Code §54-17-302 now requires PacifiCorp to obtain Commission approval, after public hearing, of any significant energy resource decision before it constructs or enters into a binding agreement to acquire the resource. Further, Utah Code §54-17-301 requires the Company to file any action plan developed as part of its IRP to enable the Commission to review and provide guidance to the Company. The resource solicitation and acquisition decision

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[5] The total of 4,679 megawatts includes the average annual amount of 500 megawatts of unspecified power purchases rather than the cumulative amount of purchases over the ten year period, which is 3,508 megawatts.

[6] PacifiCorp notes it may either build the resource or acquire it through a long-term firm power purchase agreement.

approval processes are separate from the IRP acknowledgment process. Therefore, while we may acknowledge the IRP, and may provide guidance on the IRP action plan, any approval of the solicitation and acquisition of specific resources for the implementation of that action plan will be conducted in separate approval processes required under Utah Code §54-17-201 and §54-17-302.

II. PARTIES' COMMENTS AND COMMISSION GUIDANCE

On June 4, 2007, the Commission asked interested parties to submit written comments and recommendations on IRP 2007 by July 27, 2007. On July 16, 2007, the Commission extended the comment due date to August 31, 2007, in response to such request by the Utah Committee of Consumer Services ("Committee"). The Division of Public Utilities ("Division"), the Committee, the Utah Association of Energy Users ("UAE"), Western Resource Advocates filing on behalf of itself, Utah Clean Energy and the Sierra Club (collectively "WRA"), Utah Physicians for a Healthy Environment and Utah Moms for Clean Air ("UPHE/UMCA"), Corporate Real Estate Group, LLC, ("CREG"), Mayor Ross Anderson, Salt Lake City Corporation ("SLC"), and Mayor Peter Coroon, Salt Lake County ("SL County") responded. On September 12, 2007, WRA filed errata to its comments. On October 17, 2007, PacifiCorp filed a response to these parties' comments. On December 6, 2007, WRA filed reply comments to PacifiCorp's response. On January 2, 2008, the Committee filed a request for hearing or in the alternative a request to reopen this docket for additional comments. On January 8, 2008, and January 10, 2008, the Division and Company, respectively, filed comments in response to the Committee's request.

The Company maintains IRP 2007 complies with the Commission's Guidelines and requests the Commission acknowledge and fully support the IRP and its conclusions, including the proposed action plan. UAE has concerns and provides suggestions about aspects of the IRP and planning processes, but concludes the IRP generally satisfies the Commission's Guidelines and recommends the Commission acknowledge IRP 2007. The Division, Committee, WRA, UPHE/UMCA, CREG, SLC and SL County do not recommend acknowledgment of the IRP.

The Division, Committee and WRA argue IRP 2007 does not sufficiently adhere to the Commission's Guidelines and should not be acknowledged. UPHE/UMCA, SLC and SL County support WRA's comments. While not directly addressing the issue of acknowledgment, CREG argues a variety of significant current and potential future costs are not adequately contemplated in the IRP and therefore the public is exposed to a much greater level of risk than reflected in PacifiCorp's proposal.

These comments are extensive, thoughtful and provide for varying degrees of support for aspects of IRP 2007. Parties comment on the public process, load and resource balance, resource evaluation, consideration of environmental externalities, modeling issues, link to strategic business plan, optimality of the preferred portfolio, and a decision mechanism for resource acquisition paths. We recapitulate the salient points of these comments below and provide guidance to the Company on issues raised.

A. Public Process

Commission Guidelines require an open public process and biennial filing of the IRP. All parties commend PacifiCorp for its open, public process and for its effort in developing the IRP. The Company hosted thirteen public meetings from August 2005 to June 2006, composed of five technical workshops on load forecasting, renewable energy, and demand side management and eight general public input meetings. The open meetings coupled with use of video-conferencing and telephone access allow ample opportunity for participation from Utah stakeholders.

The Division, Committee and UAE provide recommendations for further improvement of the IRP public process. While the Division believes the IRP 2007 meets the Commission's Guideline requiring an open public process, the Division believes the Company may have failed to meet one of the Commission's directives in its Report and Order on the 2004 IRP in Docket No. 05-2035-01. In that Order, the Commission instructed the Company to provide sufficient time for public input and discussion during public meetings. The Division contends significant changes were made to Company assumptions between the final public meeting in April 2007 and distribution of the draft IRP. New assumptions were adopted without full vetting, including the creation of five new portfolios, referred to as Group 2 portfolios. Changes also included a new load forecast, a 12 rather than 15 percent planning reserve for four of the five portfolios, and an additional 600 megawatts of wind resource as a fixed input and modeling constraint. Parties were given little more than three weeks to provide written comments to the Company on the draft. The Division argues these actions were not within the spirit of the Commission's directive.

Both the Division and Committee note the Company appeared to give little weight to comments made on the draft IRP and the Committee questions the value of providing such comments. The Committee suggests it may be more meaningful to have less input prior to the actual filing of the IRP and more input in the analysis and review comments to the Commission on the filed IRP.

The Division recommends PacifiCorp be held to the biennial schedule for filing the next IRP, due in late 2008, and also recommends the Company be required to file an update by the end of 2007. On January 18, 2007, the Company filed a request for extension of time to file its 2006 IRP (later renamed to IRP 2007), citing transition issues associated with the Mid-American Energy Holdings Company transaction and its interest in waiting to hear from state commissions on its then pending request for approval of a solicitation process for additional resources. The Company requested an extension to March 2007. The Division questions the timeliness of IRP 2007, scheduled to be completed in early 2007 but not filed until late May 2007. UAE recommends a revision to the Commission's Guidelines to require annual IRP filings during periods when significant resource additions are projected.

The Committee also questions how the IRP is tied to resource procurement. The Committee recommends the Commission explore how sound planning principles can be driven forward to the tangible results of new resources, that have passed the scrutiny of a least cost-least risk analytical process.

B. Load and Resource Balance

The Division and Committee voice significant concerns with the Company's calculation of load and resource balance and the resultant timing and amount of resource deficit. Both cite concerns with the load forecast and planning reserve assumptions. The Committee additionally raises an issue about how hydro generation capacity is counted in the analysis of load and resource balance.

1. Load Forecasts

The Division concludes the Company's load growth analysis is inadequate and fails to meet the relevant guideline. The Division notes the Company altered its load forecast between the public presentation on February 1, 2007, and the final public meeting on April 18, 2007, two days before the release of the draft IRP.

The Division explains the new load forecast, known as the March 2007 forecast, reflects slower Utah load growth and increased Wyoming load growth. This forecast is used for both the assessment of system load and resource balance and evaluation of the Group 2 portfolios. The overall change between the two forecasts is a slight decrease in coincident peak from 3 percent to 2.9 percent. The near term changes are a decrease of 254 megawatts in Utah load in 2009 and a 30 percent decrease in the magnitude of the deficit in the Eastern part of the Company's utility system for each of the first 3 years of the forecast (2007 to 2009). Additionally, the first year of the Company's system resource deficit is extended from 2008 to 2010. The Division argues these are significant changes in the coincident peak to be attributed to a relatively small 0.1 percent reduction in coincident peak growth rate. The Division states the Company does not provide any information to justify the change in forecast other than to say it is based on "judgment." The Division views the Company's narrative description of load forecasts as inadequate and unsupported by data sources and also at odds with the changes made to the load forecast, i.e., the narrative is general and supports continued relatively high growth in Utah demand and energy rather than the decreases shown in the new load forecast.

The Committee is concerned resource needs are understated due to the understatement of Utah peak demand growth from the new load forecast and use of normalized temperatures to develop a peak load forecast. The Committee states Utah's historical growth rates for energy, summer and winter coincident peak, and non-coincident peak all exceed the Company's March 2007 forecast. The Committee also states the Company provides little economic or demographic evidence to support the changes to its load forecast and indeed, the forecasts appear to be at odds with other publicly available forecasts regarding the Utah economy, e.g., the Utah Governor's Office of Planning and Budget's July 2007 economic and demographic forecast.

Although the Committee considers the Company's forecast methodology generally reasonable, it argues planning to a weather normalized 94 degree Fahrenheit day, based on 30 years of history, will significantly understate demand since peak demand will occur at higher temperatures. Since the Company estimates demand increases by 45-50 megawatts per degree Fahrenheit increase, demand could exceed the peak forecast by 300-450 megawatts. Further, five of the hottest summer (July) months on record in Utah have been recorded in the last seven years. Therefore, the Committee recommends the Commission require the Company to plan to a peak level that is reasonably expected to cover its actual peak, a process much more in line with industry standards. The Committee also notes the use of a 30-year period of temperature history may exacerbate the problem by using a normal temperature lower than one based on more recent history.

The Company responds its load forecast changes are most notable with respect to a slowing of growth in Utah's commercial class. The Company argues a comparison of primary economic variables and energy forecasts is instructive to understanding the reasonableness of the change in forecasts. The Company presents a graph of the ratio of Utah total retail sales to employment and states this ratio was too high for the May 2006 forecast after 2006 and therefore it made adjustments in the March 2007 forecast. Further, the Company reduced peak demand in response to its expectation of a slowing Utah housing market.

The Company also argues its load forecast analysis is adequate because its initial set of portfolio evaluations tested the impact of variations in load growth and its stochastic analysis of portfolios provided a range of load forecasts to cover nearly all possible load growth trajectories, including those in Utah. Finally, if the load forecast picture were to change dramatically, the IRP and resource procurement processes could be adjusted as required.

We find the Company's decision to change its load forecast at the end of the IRP process is inadequately supported and may be unnecessary based on its own discussion of the issue. For example, in arguing it has adequately complied with the Guideline requiring a range of estimates or forecasts of load growth, the Company cites the deterministic scenario analysis it initially performed in the Group 1 portfolios, varying the May 2006 forecast in alternative cases to test the impact of variations in load growth. Additionally, the Company points to the range of load forecasts it performed using stochastic analysis and states this range covers nearly all possible load growth trajectories including those in Utah. If this is true, we question why the Company found it necessary to change the load forecast. This decision essentially created a Group 2 set of portfolios late in the public process which the Company argues elsewhere are not directly comparable with its widely reviewed Group 1 portfolio results. Either the stochastic and scenario analyses with respect to load growth are adequate and reasonable for planning purposes or not.

In conclusion, we find the Company's use of a new load forecast in its preferred portfolio is not adequately supported and serves to obscure rather than support its planning decisions as revealed in both its load and resource balance and its preferred portfolio. The Company bears the risk associated with the extra costs of this planning decision.

There is little comment on the Company's use of stochastic and scenario analyses to provide and evaluate a range of load forecasts in IRP 2007. We direct the Company, in its next IRP process, to convene a public input meeting or technical workgroup session to review its approach to load forecast variation and to address the issue of load forecast error risk. This discussion must include the Committee's concerns regarding use of 30-year normal temperatures for estimating peak demand, the number of years relied upon for developing stochastic parameters, and the role of planning reserve in managing the risks of forecast error.

2. Planning Reserve

Both the Division and Committee argue the Company's choice of a 12 percent planning reserve in its preferred portfolio is inadequately supported; UAE disagrees.

The Division states the Company's own analysis shows a 15 percent planning reserve is better than 12 percent. The Division states the 15 percent planning reserve is consistently less risky than 12 percent and the reduction in the mean present value for a 12 percent planning reserve is insignificant. The Division argues this choice does not comply with the guideline requiring an analysis of tradeoffs, such as, between reliability, dispatchability and acquisition of lowest cost resources. The Division argues this guideline requires the Company to plan using the most economic risk/cost. Providing a comparison of the Company's own data within the IRP, the Division shows the only Group 2 portfolio based upon a 15 percent planning reserve, RA 16, is superior in almost every risk measure to the preferred portfolio, RA 14. Thus, the justification a 12 percent planning reserve is cheaper is based on slim evidence. The slight difference in the mean present values of RA 16 and RA 14 is minuscule (0.1 percent in the carbon tax scenario and 0.15 percent for the cap and trade scenario). Further, under the 12 percent planning reserve, the system becomes deficit one year later.

The Division also disagrees with the Company's argument its 12 percent planning reserve is consistent with its need for flexibility and is consistent with the guideline permitting flexibility in the planning process. The Division understands "flexibility" to mean the Company potentially avoids committing too early to technologies which subsequently go out of favor for one reason or another. However, the Division is concerned this also results in the foreclosure of operational flexibility by reducing the Company's ability to respond in different ways to changing economic and operational situations. The Division concludes the Company is unjustifiably putting ratepayers in Utah at risk. For example, the Division notes, not building today locks the Company into wholesale power purchases in the near and intermediate future and subjects it to the vagaries of the market. Therefore, the Division argues the Company also fails to comply with the guideline requiring considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent premature foreclosure of options.

The Committee argues a direct comparison of several portfolios reveals the effects of the planning reserve on expected cost and risk exposure. In all five cases the Committee considered, increasing the size of the planning reserve reduces risk. In three of the five cases, a small increase in expected cost leads to a fairly significant reduction in risk. On average, increasing the planning reserve reduces expected cost by over $60 million and reduces risk exposure by $1.3 billion. Further, the Committee contends, by choosing the 12 percent rather than 15 percent planning reserve, the Company's preferred portfolio underestimates system requirements by more than 300 megawatts in the 2012 to 2016 time period.

UAE supports the Company's planning reserve cost-risk tradeoff analysis and the use of a 12 percent planning reserve. UAE argues the results for the 12 percent and 15 percent planning reserve in both Group 1 and Group 2 portfolios show relatively minor differences in costs, upper tail risks, energy-not-served, etc., and therefore the use of a 12 percent reserve assumption is adequately supported. UAE believes the planning reserve should be used as a tool to help evaluate timing for investment in new resources and not a measure of actual system reserves. However, UAE recommends additional analysis is warranted to better incorporate macroeconomic principles such as supply and demand and price signals, specifically market response to extreme carbon risk, price caps, or other external costs and benefits.

The Company responds that selection of a planning reserve target has been one of the most contentious issues over the last two IRP cycles. The Company notes the Public Utility Commission of Oregon singled out the 15 percent planning reserve used in the 2004 IRP as a non-acknowledged element of the plan. The Company argues a 12 percent planning reserve is a reasonable starting point for a preferred portfolio because there is a trend towards more regulatory-driven resource acquisition constraints and uncertainty over the ultimate cost to ratepayers to accommodate these constraints. In addition, the Company considered its system simulation results as well as its mandate to provide least-cost electricity service in the face of increasing resource costs.

The Company considers the reliance on a fixed planning reserve level for the duration of the action plan time horizon to be ill advised given what it views as a volatile regulatory environment and resource adequacy impacts of the Company’s regional transmission expansion plan. The Company anticipates adjusting the planning reserve within a range of 12 to 15 percent as either an outcome of continued IRP portfolio analysis with updated modeling assumptions or to comply with new regional resource adequacy standards.

Based on the Division and Committee’s analysis, we conclude using a 15 percent planning reserve appears to be reasonable at this time. This is an issue that lends itself well to analysis and we direct the Company to continue to study the tradeoffs in planning to different planning reserve targets in future IRPs. The assertion by the Company of controversy regarding this issue does not serve as persuasive analytical support for its conclusions to assume a 12 percent planning reserve in its preferred portfolio. Nonetheless, the IRP is the Company's planning document and it bears the risk for any unreasonable costs associated with this planning decision.

3. Hydro Capacity Accounting

The Committee comments that sometime in the fall of 2005, the Company altered the way it calculates hydro capacity for purposes of meeting peak hour requirements. The Company now counts hydro capacity by the maximum capacity that is operationally sustainable for one hour before reserves. This approach is consistent with how control areas report hydro capacity to the Western Electric Coordinating Council ("WECC"). However, WECC cautions this approach significantly overestimates hydro availability, and WECC is in the process of developing a new method to incorporate the extent to which water flows can be sustained to provide continued energy output. The Committee raises this issue because the difference between the previous hydro capacity based on expected flows and the one-hour sustainable hydro capacity results in an improved resource position of between 640 and 450 megawatts from 2007 to 2014. The Committee raises this issue because of its overall concern the Company may not be providing sufficient firm resources to protect itself and its customers from market risk.

We direct the Company to address this issue in its next IRP. For example, it may be useful to conduct sensitivity analysis regarding this assumption to identify potential risks or shortcomings of this methodology.

C. Consistent and Comparable Resource Evaluation

The Guidelines require an evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis. The Guidelines require this evaluation include an assessment of: 1) All technically feasible generating technologies including renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources; and, 2) all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.

The Division states IRP 2007 is weak with respect to the evaluation of all resources on a comparable basis, especially with respect to renewable resources and the treatment of Class 2 Demand Side Management ("DSM"). It recommends all supply-side and demand-side resources be treated on a consistent and comparable basis in the next and future IRPs.[7]

The Committee, WRA, and SL County oppose the Company's choice to screen most renewable resources from portfolio consideration, and to use a wind resource as a proxy for all renewable resources. The Committee notes the Company excludes certain resources, like geothermal and solar, from portfolio consideration so these resources are not evaluated in the risk assessment of options. The Committee argues these higher cost but risk reducing

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[7] Class 1 DSM represents fully dispatachable or scheduled firm programs (Cool Keeper, Irrigation Load management, or interruptible or curtailment programs); Class 2 DSM represents non-dispatachable, firm energy efficiency programs (Cool Cash, Energy FinAnswer, See ya later refrigerator); Class 3 DSM represents price responsive programs (Energy exchange, time-of-use pricing plans, critical peak pricing plans, inverted tariff designs); Class 4 DSM represents energy efficiency education and non-incentive based voluntary curtailment (Power Forward).

technologies may be most beneficial in a high risk environment and exclusion of the resources means these technologies are not evaluated on a consistent and comparable basis, as required by the Guidelines. Further, the Company removes simple cycle combustion turbines ("SCCT") from the Group 2, or final five portfolios, without analytical support. WRA notes integrated gasification combined cycle power plants ("IGCC") with carbon capture and sequestration, plant retirements, and plant retrofits are not modeled because of stated modeling limitations.

WRA notes solar, geothermal, wind and other renewable forms of energy, have different cost, dispatchability, technology risk and carbon risk profiles. Just as a coal plant could not be used as a surrogate for all conventional resources, e.g., SCCTs, CCCTs, IGCC and nuclear, neither can wind be used as a surrogate for the many types of renewable resources available to the Company. The Committee and WRA also note storage technologies have been excluded from the resource selection process yet the WRA notes compressed-air energy storage, in particular, seems to hold great promise for providing dispatchability to renewable energy resources and for alleviating transmission constraints. The Committee and CREG are particularly concerned with the omission of geothermal resources, shown in the IRP 2007 list of supply options to be priced at about $38 per megawatt hour with the inclusion of a tax credit. WRA objects to excluding resources to address technology risk (the risk technology will prove uneconomic) and recommend this risk should be considered and evaluated like other risks, i.e., wholesale power price, gas price, and carbon regulation risk.

The Committee and Division also argue the amount of wind in the final five portfolios was artificially fixed and recommend the amount of wind be evaluated to determine the optimal amount of future wind additions. The Committee notes the addition of 600 megawatts of wind resource in several portfolios demonstrates, through the stochastic analysis, the potential for wind energy to mitigate wholesale power and gas price risk. From its review of three sets of relevant portfolios, the Committee observes, on average, additional wind resource investment increases expected cost by $44 million but decreases risk exposure by $921 million. What remains unclear to the Committee is whether the Company has identified the optimal quantity of wind for its system from a risk mitigation perspective.

UAE states IRP 2007 makes a good faith attempt to evaluate resource options on a consistent and comparable basis and to identify a portfolio of resources designed to minimize risk and cost. The Company's preferred portfolio includes significant new baseload coal resources, which UAE supports. However, UAE has concerns about the modeling. Proper modeling must treat all resources in a fair and unbiased fashion and the role and usefulness of the models should not be overstated. Using the Capacity Expansion Model ("CEM") and the Planning and Risk Model ("PaR"), the Company constructed 12 Group 1 risk portfolios and developed several metrics. In constructing the Group 2 portfolios, however, the CEM was restricted to choosing only between gas plants and unspecified wholesale power purchases. Wind and coal resources were effectively predetermined in the portfolios. The CEM thus became primarily a tool for determining the timing of gas resources. Given these restrictions, it is difficult to know whether the Group 2 portfolios were the best portfolios to draw from in selecting the preferred portfolio. UAE also supports active consideration of nuclear resources to meet longer-term baseload needs. To the extent coal resources become impracticable or overly expensive due to political or other considerations, UAE maintains nuclear power is a logical long-term alternative.

The Division, Committee and WRA criticize the Company's evaluation of DSM. For example, the Company uses pre-selected proxy supply curves for Class 1 and Class 3 DSM programs, thereby preventing the opportunity for the CEM to select from the full range of DSM and possibly limiting the identification of all cost effective DSM. Further, only Class 1 DSM is considered in the risk analysis.

The Division, Committee and WRA recommend the DSM potentials study [8] be evaluated in either a formal proceeding or through technical conferences where the research, evaluation, and conclusions are explained and justified.

The Committee also recommends the Company provide an actual 20-year planning horizon, rather than optimize for 12 years and then add combined cycle combustion turbines, "growth stations" in the remaining 8 years. The Committee asserts this approach is highly unusual and could lead to incorrect resource decisions being made for the first twelve years.

The Company responds its use of wind as a proxy for all forms of renewable energy is reasonable because 1) it is a mature, cost-effective and clean technology, widely available throughout the PacifiCorp service territory making it a good standard for evaluating the risk-reduction effects of renewable energy; 2) it is consistent with the modeling approach used in the 2004 IRP and has been previously acknowledged and was discussed at a technical conference with no opposition at that time; and 3) the CEM may not have been able to handle additional technologies. With respect to the amount of wind resource assumed, the Company argues it was

[8] "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources," June 11, 2007, Quantec LLC.

not arbitrary because it had evaluated this amount as part of the Group 1 portfolio analysis. However, the Company agrees additional wind resource analysis is warranted. Its priority for additional analysis is to determine how to represent state and federal renewable portfolio standards (“RPS”) requirements as accurately as possible given model design constraints, and subsequently determine the resource strategy that meets the best cost/risk standard given these regulatory resource requirements.

With respect to the DSM limitations, the Company states the Class 2 DSM decrement analysis and planned DSM targets represent an interim resource planning strategy to guide the Company until the results of the multi-state DSM potentials study could be incorporated into the IRP modeling process. Concerning the evaluation of Class 2 DSM’s risk reduction effects, the use of stochastic simulations captures the stochastic risk reduction resulting from fewer spot market purchases, reduced use of natural gas, and re-optimized operation of current and IRP resources due to the addition of the Class 2 DSM resource in the preferred portfolio. Resource deferral is reflected in the results of the CEM since more resources would have been added had the Class 2 DSM not been included in the retail forecast. Given lessons learned from this IRP and the expansion of options arising from the June 2007 DSM potentials study, the Company intends to explore new methods to accommodate a broader range of technologies.

Finally, the Company argues the IRP does not identify specific resources to procure. Such decisions will be made subsequently on a case-by-case basis with an evaluation of competing resource options including updated available information on technological and environmental factors and electric and natural gas price projections. These options will be fully developed using competitive bidding or other procurement processes. Resources such as solar projects can be evaluated or selected through a competitive solicitation process. Conversely, by including named resource types in the preferred portfolio, the Company has not committed to building specific resources. This misconception stems from confusion about a proxy resource in portfolio evaluation; the purpose of a proxy resource is to represent the indicative characteristics of an asset-type resource that might be procured. When included in the preferred portfolio, the proxy resource informs action plan development and selection of benchmark resources for competitive procurement. It does not imply the Company will procure the specific resource or even a technology.

We agree with the Division, Committee and WRA, that IRP 2007 does not comply with our requirement for consistent and comparable evaluation of all feasible resources. While it is reasonable the Company will carry forward its analytical process in selecting among actual, rather than proxy, resources in a competitive solicitation, this does not replace the importance of the IRP in understanding the expected costs and risks of different types, amounts and timing of resources that serve the public interest in the long run. A competitive solicitation uses benchmark resources to form a baseline of least cost/least risk resources against which bids may be evaluated. We direct the Company to evaluate a full spectrum of supply-side and demand-side options which have different characteristics regarding size, dispatchability, expected cost, expected risks and lead time for construction. Modeling limitations will need to be addressed.

As a priority in wind resource evaluation, we concur with the Committee the Company must first identify the optimal amount of wind resource under different circumstances and to understand its value in terms of the tradeoffs of expected cost and risk reduction. Once this step has been completed, then constraints regarding state or federal RPS requirements can be evaluated to determine whether the optimal levels of wind additions generally satisfy these requirements, or if not, whether there is additional and material cost associated with meeting these requirements. This second stage is important for multi-state discussions regarding interjurisdictional cost allocation.

Regarding the DSM analysis, we agree with the Division, Committee, and WRA that IRP 2007 falls short of a full examination of the potential of DSM in the optimal portfolio. We concur with these parties the DSM potentials study should be examined prior to use and plan to open a docket for this purpose.

D. Consideration of External Costs

The Guidelines require a range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Division recommends the Company expand its current analysis which provides scenario analysis for a range of carbon dioxide (“CO_2") adders and a single cost for other pollutants, i.e., sulphur oxides (“SO_x”), nitrogen oxides (“NO_x”) and mercury. The Division recommends future IRPs discuss, and where possible, quantify all externalities, both positive and negative, that can be identified, including societal health effects from activities associated with the Company’s operations, climate change, and impacts on local and regional economies. The Committee recommends the Commission provide more specific direction to the Company on its inclusion and use of externality values in order to provide a more robust picture of all costs involved with certain resource choices.

WRA , SLC, SL County, UPHE/UMCA, and CREG argue the IRP fails to accurately and thoroughly address the negative externalities imposed on the public by an over-reliance on coal-fired power plants. WRA states the range of CO_2 adders is not adequate and the list of externalities too limited. Only the direct cost of anticipated regulation of CO_2, NO_x, sulphur dioxide and mercury is considered. WRA understands the Guidelines to require the utility to assess the societal costs of all externalities, not just externalities to the extent they may be internalized in the future. The Company should be required to augment its risk-assessment analysis with assessing the impacts of resource choices which will not be reflected in the resource price, i.e., public health impacts, regional haze and air pollution, climate change, wildlife impacts, and disruption of Native American religious sites, noise, etc. Furthermore, the external cost of mercury, in terms of health effects, may be much greater than the cost of removal. Given the modest cost differences among tested scenarios and portfolios, appropriate consideration of the excluded impacts may alter the ultimate portfolio selection.

WRA argues the Company assigns too great a weight to minor differences in cost. For example, RA6, which includes no pulverized coal, is expected to increase rates by $3.31 per megawatt hour. The scenario with the lowest rate impact, RA1, raises rates $3.08 per megawatt hour. This difference is well within what WRA considers to be the margin of error of the Company’s analysis, and even if accurate, amounts to an average rate differential of only $0.00023 per kilowatt hour. For a typical residential customer consuming 600 kilowatt hours per month this means the Company could avoid the risks and impacts of additional coal for about 12 cents per month.

UPHE/UMCA argue there is no safe level of air pollution. Citing broad-based scientific studies, mainstream medical organizations like the American Lung Association have estimated the nationwide annual number of premature deaths caused by the air pollution from coal power plants at 22,000 to 26,000, or an average of 40 deaths per year per plant. Causes of these deaths include heart attacks, strokes, respiratory failure, lung cancer and a variety of events unique to children. In assessing the economic impact of fatalities, the United States Environmental Protection Agency uses a figure of over $6 million per life lost. According to the California Environmental Protection Agency, the total health care costs from coal plant air pollution exceeds $170 billion. If charged directly to the consumer, the costs of the public health impacts from coal power plant air pollution would essentially double the cost of the electricity. CREG argues the cost not borne in Utah's electric power rates but rather paid through the health system is approximately equal to a 50 percent increase in the installed cost of coal ($20 per megawatt hour on the low end). All other energy sources included in the IRP do not impose this high of a burden on Utah citizens' health.

WRA argues the Company's CO_2 analysis does not address recent policy decisions by western Governors, including Utah's Governor Huntsman, to reduce regional greenhouse gas emissions through a western climate initiative. The IRP fails to adequately consider the risk of controlling or offsetting CO_2 emissions due to inappropriate model inputs and the manner in which the analysis averages the results of all its assessed alternative futures. Critically, the Company's proposed portfolio will negate the opportunity for the state's electric sector to meet the regional emission reduction target of the western climate initiative.

WRA disagrees with the Company's range of CO_2 adders arguing the values are too low, especially with regard to the use of adders in the scenario analysis performed using CEM. WRA argues the western climate initiative will subject the Company to the cost of CO_2 allowance purchases and those allowances will not be free under any foreseeable circumstance. Although WRA believes the high adder value in the scenario analysis of $38 per ton of CO_2 in 2008 dollars is reasonable, this value was applied to only 6 of 16 alternative future scenarios. Subsequently, the Company evaluates the results of its alternative future scenarios using a simple averaging methodology. Specifically, the weight placed on the low, medium and high CO_2 adder values is based on the number of alterative future scenarios run with each input. Of the 16 alternative scenarios, the Company ran seven with a $0 per ton adder, three with the $8 per ton value and six with the $38 per ton value. The average of the results of these analyses were then used to feed inputs for further evaluation.

In its stochastic risk analysis, WRA notes the Company broadened the range of adders raising the high value to $61 per ton of CO_2. However, because of starting date assumptions and use of a relatively high discount rate, only minimal variation among the various CO_2 adder scenarios was tested. For the first seven years of the IRP analysis period, all CO_2 adder cases are exactly the same and incorporate only modest adder values. Due to the slow escalation to target values and too high a discount rate, differences in the resulting present values were relatively negligible ($14.71 per ton of CO_2 in the high $61 case through 2019). Thus, the CO_2 adder scenarios show minimal variation in the risk exposure from the various CO_2 adder cases tested and this treatment of future risk greatly undermines its importance in the future.

WRA recommends better analysis on the appropriate discount rate to use in the future in order to allow full assessment of the impact on current and future generations.

The WRA and CREG contend the IRP fails to capture the volatility or increasing cost of coal as a fuel source. WRA states the high value in four of the Company's 16 alternative future scenarios include a high value which adds a 20 percent premium to the reference coal price forecast. WRA states from 2003 to 2006, coal prices in Utah have increased 68 percent.

UAE comments the IRP's discussion of various externalities generally satisfies the Guidelines. However, both UAE and WRA are concerned about what UAE characterizes as the unintended consequences of building large natural gas-fired electric plants to meet baseload electric needs. Natural gas prices are extremely volatile and competition from gas-fired power plants increases local prices and volatility, harming Utah industries and the Utah economy. UAE recommends incentives be provided to encourage cogeneration because it is a more efficient means for generating power from natural gas. WRA argues the failure of the IRP to examine the impact of purchases of natural gas on natural gas price undervalues alternatives, like renewable energy and DSM, that reduce rather than increase purchases of natural gas.

The Company responds its approach for considering environmental externalities in this IRP as well as past IRPs has been in compliance with IRP standards and guidelines. Nonetheless, in response to stakeholder recommendations to treat environmental externalities more comprehensively, the Company tasked Quantec LLC to conduct an externality study as part of the multi-state DSM potentials study. The purpose of the study was to 1) review and synthesize literature on including externalities in utility resource planning, valuation methods, and ranges for their values, 2) determine the ranges of likely externality values (including monetary, where possible) and 3) assess the sensitivity of IRP outcomes to probable ranges. Additional externalities for evaluation not previously covered in past IRPs include impacts on water use and water quality, impacts on land use, environmental impacts of wind on wildlife, effects of global climate change on the hydroelectric system, and carbon sequestration. This study will serve as a useful basis with which to determine how the Company can feasibly address externality analysis in future IRPs given available research, corporate scientific expertise, the overall IRP workload, and Company and stakeholder analytical priorities.

We generally find the Company's approach to evaluating the potential environmental impacts of alternative resource acquisition strategies, i.e., scenario and risk analysis, to be reasonable. We provide further guidance for improving these analytical processes later when we address the issue of optimality. However, comments concerning the unexamined health impacts of alternative types of generation technologies are much more comprehensive than in the past and we concur with all parties that further expansion of the type of external costs considered is required going forward. We understand the Utah Geological Survey is examining how to include other externalities in utility planning processes and we expect this work, when it is available, to be taken into consideration by the Company. In the meantime, we concur the multi-state DSM potentials study can be a starting point for further discussion. Again, we plan to open a docket to examine this study. Further, we direct the Company to host a public input meeting or technical workgroup to examine the reasonableness of the range of CO_2 adders for evaluating carbon regulation risk and risk mitigating resource strategies.

E. Modeling Issues

The Division recommends the Company rethink how to use its computer models to derive portfolios for the next IRP and to better explain the process it uses. The Division argues the Company's approach for developing portfolios is confusing. This process entails making scenario runs with the CEM, selecting individual resources based on frequency counts in the scenarios, taking these selected resources and shuffling them into new portfolios for further risk analysis using the PaR model. The result is an apparently inconsistent use of these sophisticated computer models throughout the process.

Both the Division and UAE recommend more detailed education of the Division and other interested parties by allowing "hands on" experience of providing inputs into these models and observing the outputs. UAE argues the quality of public input will be significantly increased if regulators and other interested parties are permitted to access, operate and verify all of the data, spreadsheets, models and information used in the IRP.

The Committee supports the Company's adoption of software containing automatic resource optimization logic; the CEM for its scenario analysis; and inclusion of IGCC, wind and short-term wholesale power purchases in the risk modeling. The CEM performs automatic economic screening of generation supply-side and demand-side resources and determines the optimal resource expansion plan for a specified planning scenario. However, the Committee argues additional work remains in order to achieve a modeling process which can provide an accurate and comprehensive view of the tradeoffs associated with various resource choices providing regulators and policy makers with results leading to meaningful policy discussion and decisions. Specifically, the Committee objects to the pre-screening and exclusion of resources available for CEM selection, the exclusion of resources available for selection in the latter part of the 20-year period of analysis, and recommends additional work regarding the consideration of external costs.

We concur the Company's tools could be used to produce a more transparent evaluation of options, risk and uncertainty. We provide further guidance to the Company on this issue later in this Order when we address the issue of optimality.

F. Business Plan Link

Commission Guidelines require the Company's strategic business plan to be directly related to the IRP to ensure ratepayers receive the benefits from IRP. The Division and Committee contend the IRP 2007 is problematic with respect to this guideline. Although the Division is unclear what, exactly, the Business Plan is, it notes something does appear to have influenced the results of the IRP in a way that is not transparent. The Division states several assumptions were changed without attendant analysis supporting the changes, i.e., the change to a 12 percent planning reserve and adoption of expanded use of unspecified power purchases. Further, the Company's comment "[t]he modeling is intended to support rather than overshadow the expert judgement of the PacifiCorp's decision makers" implies a link.

The Committee's understanding of the link between the IRP and the business plan is as follows. Portfolios RA1 through RA12 were developed in a first round of risk analysis and the Company's 10-year business plan, unveiled to regulators in early 2007, was based on the preliminary results from this phase of analysis and RA5 was most like this business plan schedule of investments. Then, the Committee explains, based on its assessment of state policy directions, the Company investigated alternatives to the business plan investment schedule and developed five additional portfolios, RA13 through RA17, and selected RA14 as the preferred portfolio. The Committee argues the approach taken by the Company, i.e., determination of the primary components of the resource plan outside of the IRP process without a transparent explanation, has obfuscated rather than clarified important cost/risk tradeoffs.

The Company responds by describing several Company resource planning efforts: 1) a PacifiCorp 10-year business plan that is conducted on an annual cycle; 2) an IRP process conducted on a biennial cycle; and 3) an overall corporate planning process of which the IRP is a part. Initial IRP modeling results informed the selection of the generation capital additions assumed for the business plan which was finalized and approved in December 2006 and is referred to as the 2006 business plan. The Company explains the business plan attempts to project utility costs as accurately as possible and requires more precise cost estimates and more frequent assumption updates than the IRP. The IRP portfolio analysis conducted in 2007 was not a product of the business plan but rather reflected a resource policy decision in the overall corporate planning process. This resource policy decision included the Company's assessment that a preferred portfolio with four supercritical pulverized coal plants could not get acknowledged by all state commissions. Therefore, the Company decided to model portfolios with only two supercritical coal plants and these are referred to in the Group 2 portfolios.[9] The Company also states the amount of unspecified power purchases was not dictated by the 2006 business plan and as proof of this states the portfolio that best models the business plan portfolio relies to a greater extent on unspecified power purchases than the preferred portfolio.

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[9] One of the Group 2 portfolios, RA 13, models four supercritical coal plants.

The Company further explains it is doing its best to keep the IRP and business plans consistent to the degree permitted by their respective development cycles and data requirements. The Company proposes, as a practical solution to the IRP/business plan linkage issues, using its IRP models and portfolio analysis methodology as an integral tool set for developing a refreshed preferred portfolio and associated planning scenarios in support of the Company's business planning efforts.

The reason for this guideline is to ensure ratepayers receive the benefits of IRP. To the extent the Company makes business or corporate decisions affecting its view of the optimal resource plan given its expected combination of costs, risks and uncertainty, it must also provide the necessary analysis in the IRP to enable us to determine its conclusions are consistent with the public interest. This is what it means to link the two processes together.

The IRP must serve as an analytical document of the costs and risks to ratepayers of alternative means of providing for adequate future service. Clearly, many considerations play a part in the Company's decisions. However, our Guidelines require not only an assessment of risks and uncertainties, but also requires the Company identify who is expected to bear the cost to mitigate this risk. If the Company believes it faces a financial risk due to an IRP failing to be acknowledged in one jurisdiction or another, it has the obligation in the IRP to identify the potential cost consequences of this event and the cost to ratepayers to mitigate the risk.

In order to persuade us the additional cost of reducing the number of coal plants from four to two is in the public interest for the reasons presented by the Company, we must know how customers benefit by this change. Implicit in the Company's decision is the notion that customers benefit by the reduction in the number of coal plants. However, no analysis of customer benefit is provided by the Company in support of its decision. It is critically important the IRP process produces credible results upon which state commissions can rely prior to the use of constraining assumptions based on asserted corporate financial risks.

Therefore, we instruct the Company to ensure the IRP explicitly produces the quantitative analysis necessary for regulators to understand the cost consequences of mitigating any risky or uncertain event including any Company corporate resource planning decision. The Company bears the risk for any unreasonable cost to ratepayers associated with its decision to change the quantity and type of resources it procures based on asserted but unexamined risks.

G. Optimality of the Company's Preferred Portfolio

The Division and Committee argue IRP 2007 does not comply with the guideline stating the IRP should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty. The Division argues the Company has its own definition of and goals for the IRP which are not consistent with the Commission's definition of an IRP. The Division believes the Company's conclusion stated in the IRP, "The emphasis of the IRP is to determine the most robust resource plan under a reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future," is a clear rejection of the Guideline. The Division counters the Company's contention that states have not defined "optimal," by arguing the Company has not defined "robust."

The Committee argues the Company's preferred portfolio is neither optimal "given the expected combination of costs, risk and uncertainty," nor is it consistent with the Company's analysis. The Committee believes two key elements to consider in evaluating the optimality of a portfolio are its expected cost and risk exposure. Ideally, the portfolio with the lowest expected cost would also have the lowest expected risk. However, often there is a tradeoff between the two; lower risk portfolios can be associated with a higher expected cost and vice versa. Understanding the magnitude of these tradeoffs is essential to sound decision making.

The Committee presents a graph showing the cost and risk tradeoffs of the seventeen portfolios the Company developed for risk analysis under the average carbon adder value case. The graph makes clear the variation in expected cost is quite small across the seventeen portfolios as compared to the variation in risk exposure. In the average carbon value adder case, the portfolio with the highest expected cost is 4.6 percent greater than the portfolio with the lowest expected cost. However the risk exposure of the riskiest portfolio is 46.4 percent greater than the risk exposure of the least risky. Thus, the Committee believes risk exposure should play a primary role in selecting the preferred portfolio.

The Committee contends RA 14 is not the optimal set of resources given the expected combination of costs, risk and uncertainty. The Company's preferred portfolio, RA 14, has the lowest expected cost of the seventeen portfolios modeled, however, it is one of the riskiest plans evaluated; only two are riskier. RA 14 includes short-term, unspecified, power purchases after 2011 and builds to a 12 percent planning reserve. The inclusion of these components is contrary to the conclusions easily drawn from a more explicit examination of these issues. The Company developed several portfolios wherein a direct comparison of the strategy of relying on the market can be compared with the strategy of firming short-term transactions with CCCTs. In four cases, firming market transactions with CCCTs reduces risk. In 3 of the 4 cases, expected cost was also reduced. Only one case resulted in a cost-risk tradeoff. On average, firming market purchases lowers expected cost by $122 million and reduces risk exposure by $862 million.

Both the Division and Committee are concerned with the Company's reliance on the wholesale power market. While the Company indicates this market is liquid enough to support its continued use of short-term wholesale power purchases, citing it has received offers of over 5,000 megawatts for delivery between 2007 and 2012, the Committee remains unconvinced those same megawatts would be available beyond 2012. For example, the draft WECC 2007 Power Supply Assessment indicates without additional plants beyond those currently under construction or in the regulatory process in the near future, large segments of the West will be deficient in 2012. It also indicates if resources currently in the regulatory process are not approved or are delayed, deficits could appear as early as 2009. The Division recommends future IRPs contain a detailed discussion of the wholesale power market itself and the availability of power the Company expects to purchase from this market at its forward prices.

Further, the Division argues the basis of the near-term decline in the Company's projections of natural gas and electric prices before they return to a trend is inadequately explained. These price curves likely had a major effect on the model's selection of resources. The Committee is also concerned the cost/risk tradeoff analysis may not fully capture the risk of natural gas and wholesale power price volatility. This is because the stochastic analysis uses historical volatility to project future volatility and would therefore miss any fundamental shift in these markets brought about by climate change policy. For example, the Committee provides an exhibit of how carbon policy could affect the cost-risk tradeoffs of alternative resource selections. It shows little change in the ranking of cost risk tradeoff pairs as the carbon value adder rises. This is because wholesale power and gas price risk dominate cost-risk tradeoffs, even with a high carbon adder value. Also, the modeling may not fully capture the risk of natural gas and wholesale power price volatility because the modeled cost of energy-not-served, $400 per megawatt hour, may be too low. The Federal Energy Regulatory Commission is expected to increase this cap to $1,000 per megawatt hour as part of the CAISO Market Redesign and Technology Upgrade. When this occurs, emergency power may be priced far in excess of $400 per megawatt hour.

The Company responds it has not redefined the IRP by using robustness as a decision criterion for determining optimality under risk and uncertainty. The Company argues the IRP does not permit mathematical optimality under a single objective function as suggested by the Division. Instead, the IRP is a multi-objective and partly qualitative decision framework. In the former case, an optimal solution can be found given deterministic assumptions and disregarding risk.

Rather, the Company argues it has defined “robust” in this IRP as an individual resource or portfolio that performs well under a range of alternative futures (in the context of modeling with the CEM) or stochastic simulations based on different CO_2 cost scenarios. The Company submits the concept of portfolio robustness is the only appropriate optimality decision criterion that can be applied to account for risk and uncertainty as directed by the Commission and challenges the Division to come up with an alternate optimality criterion that does the same.

The Company also argues it is not valid to compare the performance attributes of the Group 2 risk analysis portfolios with those of the Group 1 portfolios because the Company uses different load forecasts for the two Groups. Other differences include an accelerated wind investment schedule the Company argues addresses state renewable portfolio standards.

The Company also disagrees with the Committee's conclusion that risk exposure should dominate the cost-risk tradeoff analysis because of the greater magnitude of risk exposure relative to expected cost. The Company argues this essentially means a dollar of risk reduction is approximately worth a dollar of expected costs and this assumption represents an extreme "risk averse" position. The Company states it does not assume a level of risk aversion in judging the relative importance of risk exposure and expected cost due to the subjective and controversial nature of such an assumption.

Further the Company argues it used the same process to develop the Group 2 portfolios as it did with the Group 1 portfolios. In short, the CEM was first used to initially screen resources and ensure there is sufficient capacity to meet planning reserve targets. Based on the screening results, the Company then manually crafted a set of portfolios to test alternative resource strategies. The Company plans to revisit this overall approach to develop portfolios in the next IRP based on experience in using the CEM, lessons learned from assimilating the results of two models (CEM and PaR) with distinctly different analysis objectives, and vendor improvements to the models.

As for the Division's concern of inadequate vetting of the Group 2 portfolios, the Company argues it developed these portfolios to address new state resource preferences not accounted for in the portfolio analysis. As evidence of this need, the Company cites the Public Utility Commission of Oregon's requirement the Company's IRP "must be consistent with the long-run public interest as expressed in Oregon and federal energy policies" and the Washington

Public Utilities and Transportation Commission rules requiring the Company account for “public policies regarding resource preference adopted by Washington state or the federal government” in its portfolio analysis.

Finally, the Company disagrees with the Committee’s concern of over reliance on unspecified power purchases because it has allowed the resources to be selected on a comparable basis with other resources and the resources were assigned wholesale power price risk in the stochastic analysis. The Company contends there is no basis to expect short-term wholesale power purchases will not be available after 2012. Factors like additional transmission could contribute significantly to supply adequacy in the PacifiCorp system. Further, including the regulatory cost of greenhouse gas emission control and renewable generation requirements could dampen electricity demand growth from what is currently projected. Finally, the Company states it used cost-risk tradeoff analysis between unspecified power purchases and combined cycle combustion turbines, along with non-modeling considerations including planning flexibility, resource diversity and capital budget impacts, to ascribe to unspecified market purchases the role of a bridging resource.

We commend the Company for the progress made in IRP 2007 with respect to the greater utilization of computer software to develop portfolios based on automatic resource addition logic and to evaluate the stochastic risks of alternative portfolios. We observe IRP 2007 includes valuable information regarding the expected costs and risks of alternative portfolios and consider this effort a progressive step in IRP analysis. However, we cannot determine from either the information in the IRP or from parties’ comments that the Company’s preferred portfolio is either “optimal” or “robust.”

Any resource plan resulting from a linear programming model, like CEM, is optimal by definition for the specified set of input assumptions modeled. A robust plan is one that performs well under a variety of input assumptions, and is certainly a desirable outcome. We find no clear path leading us from the Company's analysis of costs, risks and uncertainty through its CEM and PaR results to determine whether RA 14 is optimal under any specific set of input assumptions, nor whether it is robust. We believe the metrics for a proper analysis are available, but the full analysis regarding costs versus risk reduction by the Company in support of its preferred portfolio is absent.

In the next IRP, we direct the Company to consider the following three-step approach for developing its optimal portfolio: 1) Identify optimal portfolios for a relatively broad, and consistently applied, set of input assumptions; 2) subject all of these optimal portfolios to stochastic risk analysis and identify superior optimal portfolios with respect to the tradeoff between expected cost and risk exposure; 3) examine the cost consequences of the superior portfolios with respect to uncertainty by subjecting them to evaluation under the initial set of relatively broad input assumptions. The key difference in this approach and the approach used by the Company in IRP 2007 is we omit the frequency counts and creation of hand-built portfolios that are difficult to associate with any specific set of input assumptions and therefore the prevailing conditions for which the portfolio is lowest cost. By consistently applying sets of input assumptions in the creation of optimal portfolios, a wide range of resource types can be available for risk analysis, and the potential for an artificial bias in resource selection will be reduced. Finally, in the next IRP or IRP update, the Company must explain the input assumptions for which its preferred portfolio is optimal and explain how it is the superior portfolio with respect to cost, risk and uncertainty.

H. Resource Acquisition Paths and Decision Mechanism

The Guidelines require a plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds. The Division, Committee and WRA conclude the Company did not comply with this Guideline. The Division states there are no formal decision mechanisms or known triggers to respond to changes as the future unfolds. The Division states failure to plan for future alternatives, or at least to describe a decision mechanism for determining the Company's responses to changing situations, is a significant shortcoming of this IRP given the potential for widely divergent results as indicated by the different scenarios including alternative potential CO_2 adder levels considered in the IRP. The Committee states the Company "...has not presented any clear decision mechanism or path to modify its plan, except to the extent that it presents updates to its IRP and deviations from its IRP in its actual resource acquisition process and business planning."

The Company proposes a modeling framework for acquisition path analysis that is performed in its evaluation of competitive bids and its benchmarks. The Company argues modeling the bids and benchmarks under various scenarios, both before and after stochastic simulation, will help assure the bid resource finalists are robust with respect to cost and cost variability under alternative economic and planning assumptions. The Company contends the development of a decision mechanism and alternative acquisition paths should logically occur after this modeling effort has been completed since alternative acquisition paths are contingent on the specific resources the Company is planning to acquire and should not be based on the proxy resources identified in the IRP.

The purpose of this guideline is to provide resource acquisition path contingencies for big picture changes affecting the type, amount and timing of resources to produce a least cost expansion plan considering risk and uncertainty. Recent events like the legal challenges facing the third unit at the Intermountain Power Plant underscore the need for this component of the plan. For example, CEM scenarios which do not select coal resources, for whatever reason, select or utilize a very different set of resources to minimize cost. If assumptions affecting the viability of coal as a low cost resource were to change to the extent coal is no longer selected by CEM, the resource acquisition path would shift to alternative resources. The optimal combination of these remaining resources would be subject to risk and uncertainty analysis which may further inform an optimal alternative resource path. The Company's approach to addressing this guideline does not produce this same result. Indeed, it occurs outside of the IRP process and in the solicitation approval process which has tighter time constraints and may preclude some resources from analysis.

We do not intend the IRP to be a static document. Rather, it should serve as a planning guide identifying prudent courses of action to serve the public interest under a variety of circumstances. Assumptions driving IRP results can change within a two-year look which is exactly why a reasonably broad range of alternative assumptions must be considered in the IRP process and a decision mechanism must be identified to select from among and to modify the resulting resource acquisition paths as the future unfolds. This Guideline serves the purpose of informing decision makers and interested parties of the probable consequences of the changed circumstances.

We conclude the IRP going forward must fully satisfy this guideline. We direct the Company, with public input, to develop a manageable set of potential future conditions, defined by a consistently applied set of input assumptions, and to develop a set of optimal portfolios consistent with these sets of conditions. These optimal portfolios should be evaluated for risk and uncertainty. The IRP action plan should be the optimal plan given the Company's expectation of the combination of costs, risk and uncertainty as supported by analysis. The set of conditions for which this plan is deemed to be optimal should be transparent and contingency plans should be identified in the event a material change in these conditions occurs. This approach may also assist in the efficient management of future resource solicitation and acquisition processes.

III. CONCLUSION

We are encouraged by the level of support for the IRP public input process and commend the Company for the progress it has made in developing computer tools to identify optimal portfolios and evaluate risk. However, we are concerned by the lack of support for the filed IRP 2007 given the opportunities for, and expressed exercise of, public input during meetings and on the draft IRP. While there is much value in IRP 2007, we are persuaded the Company has not adequately adhered to the Guidelines and therefore do not acknowledge IRP 2007.

Specifically, this IRP has not adequately adhered to our guidelines requiring consideration of all resources on a consistent and comparable basis, a link to the strategic business plan to ensure customer benefits of IRP, the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty, and different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.

Rather than direct modifications to this plan, we provide guidance herein to the Company to assist in the development of the next IRP. We affirm the importance of the IRP process from a public interest perspective and encourage the Company to continue its efforts to improve and refine the process, especially given the forecasted need for significant new resources in the future.

IV. ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED, that

1. The IRP 2007 is not acknowledged.

DATED at Salt Lake City, Utah, this 6th day of February, 2008.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#56234