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PACIFICORP
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June 6, 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 Oregon Party Comments on PacifiCorp's Integrated Resource Plan

PacifiCorp (dba Pacific Power & Light Company) submits for electronic filing, PacifiCorp's Responses to Oregon Party 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 7900-4437-3802.

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

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

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825 NE Multnomah, Suite 800
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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 6th day of June, 2005 I caused to be served, via Federal Express or email to those with an email address, a true and correct copy of the Responses to Oregon Party Comments on Pacificorp's Integrated Resource Plan (Docket No. LC-39).

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Response to Oregon Party Comments on PacifiCorp's Integrated Resource Plan

(Docket No. LC-39)

INTRODUCTION

This document provides a summary of the substantive comments submitted by the parties, along with PacifiCorp's responses.

PacifiCorp's 2004 IRP was filed with the Oregon Commission on January 20, 2005. On March 21, 2005, the Commission issued an invitation under Docket No. LC-39 to submit comments on PacifiCorp's IRP by May 18, 2005. The due date for comments was subsequently extended to May 23. Five parties submitted comments by the extended deadline:

- Oregon Department of Energy (ODOE)
- Northwest Energy Coalition (NWEC)
- Citizens Utility Board of Oregon (CUB)
- Renewable Northwest Project (RNP)
- Hydropower Reform Coalition – WaterWatch of Oregon (HRC-WW)

PacifiCorp appreciates the comments received from the five Oregon parties, and welcomes the opportunity to respond to them prior to a Commission acknowledgement decision. We emphasize that the IRP process is dynamic, and that PacifiCorp strives to develop an IRP that is robust with respect to accounting for alternative futures and changing circumstances. PacifiCorp also devotes significant effort to address stakeholder concerns and accommodate multiple stakeholder viewpoints and analysis requests. Ultimately, we believe that effective engagement by all parties is crucial to the success of the IRP process.

The key premise raised by the parties is that PacifiCorp's Preferred Portfolio does not represent the optimal portfolio from a long-run public interest perspective due to the timing and magnitude of coal plant investments and inadequate attention given to low CO_2-risk resource options such as renewables, Demand Side Management, and gas-fired combined cycle units. Most of the parties recommended that the Commission reject new coal plants stemming from PacifiCorp's Action Plan, or not acknowledge the IRP until the Company conducts further portfolio analysis with greater emphasis on low CO_2-risk resource options. The issues and criticisms surrounding CO_2 costs and coal plant investment can be summarized into five main themes:

- PacifiCorp significantly underestimates climate change risk and the potential cost impacts of CO_2 regulatory compliance.

- PacifiCorp's apparent urgency for investing in coal plants is misguided given (1) the significant potential CO_2 costs, (2) cost recovery risks attributable to such large, long-term investments, and (3) the availability of other more flexible, shorter lead-time resources.

- PacifiCorp did not adequately assess the comparative risks of coal versus gas-fired resources, and therefore its cost justification for the Preferred Portfolio—with its two proxy coal resources—is weak relative to alternative gas-intensive portfolios.

- PacifiCorp undervalued the potential CO_2 cost/fuel price risk mitigation contributions and other system benefits of renewable resources, and failed to analyze portfolios that assumed an expanded renewable resource base beyond the 1,400 MW target identified in the Action Plan.

- As with renewables, PacifiCorp undervalues DSM for mitigating CO_2 cost and fuel price risks; the Company should also be more aggressive in pursuing DSM opportunities.

Since these issues and criticisms relate to the parties' recommendations regarding IRP acknowledgement, PacifiCorp addresses them first. Comments and responses on other topics, specifically Integrated Gasification Combined Cycle technology, hydroelectric relicensing, and distribution generation resources, will follow.

UNDERESTIMATION OF CLIMATE CHANGE AND CO_2 REGULATORY COST RISKS

The parties levied three basic criticisms of PacifiCorp's handling of CO_2 cost risks:

- PacifiCorp's base case CO_2 adder is low or obsolete based on current state, federal, and international regulatory developments.

- Inadequate attention was given to Oregon-specific CO_2 regulatory activities, leaving PacifiCorp unprepared in the event of relatively rapid changes in the regulatory environment.

- PacifiCorp failed to consider alternative CO_2 regulatory scenarios and assumptions; in particular, inadequate attention was given to constraints on a cap and trade strategy and the associated availability of CO_2 offsets.

Nearly all the parties stated that PacifiCorp underestimates climate change risk and the potential cost impacts of regulatory compliance by virtue of assuming a base case CO_2 cost adder assumption that is too low at $8/ton in 2008 dollars. Parties such as NWEC and RNP cited other Western utilities (Xcel Energy, Idaho Power) or regulatory jurisdictions (California) that now assume a higher base allowance cost for utility resource planning. ODOE cited studies indicating that high CO_2 adders are needed to stabilize CO_2 emissions to levels in line with various climate change mitigation proposals.

Concerning Oregon CO_2 regulatory policy, ODOE and CUB referred to the apparent regulatory momentum building in Oregon for a state-level CO_2 mitigation policy, and along with NWEC, cited the proposals stemming from the Governor's Advisory Group on Global Warming as evidence of this momentum. ODOE and CUB claim that PacifiCorp has not adequately considered the implications of such Oregon CO_2 emission reduction targets, particularly considering the increase in CO_2 emissions forecasted for the Preferred Portfolio. ODOE further claims that PacifiCorp's "proposed action plan leaves it unprepared for possible changes in Oregon laws." CUB also states that committing Oregon ratepayers to coal plant investments prior to establishment of Oregon's CO_2 regulatory regime and associated costs "seems irresponsible at best."

Regarding CO_2 offsets, a number of the parties claim that PacifiCorp gave inadequate attention to alternative assumptions regarding the availability or costs of CO_2 offsets under a cap-and-trade regulatory regime. ODOE cited two problems with PacifiCorp's CO_2 allowance impact analysis. First, the Company did not perform a scenario analysis assuming a firm constraint on CO_2 emissions without an opportunity to sell or buy offsets. Second, in order to support a low base case CO_2 adder (below $10/ton), PacifiCorp must have assumed a large supply of low-cost CO_2 offsets, which is questionable given the limited offset potential in various energy sectors and from biological sequestration. On this later point, NWEC warned PacifiCorp that the availability of low-cost CO_2 offsets is probably limited, and recommended that the Company aggressively acquire offsets now.

PacifiCorp's Response:

The three main concerns outlined above are addressed in order.

Base Case CO_2 Adder is Too Low

The selection of an $8.38/ton CO_2 adder with annual inflation adjustment is based on observations of a number of policy and market analyses in the US and overseas. We are confident that recent developments support our estimate and strongly discourage revision of the adder:

- The National Commission on Energy Policy (NCEP), a bipartisan group of leaders in the energy industry, released the results of their year-long deliberations on national energy policy. Among other policies, the NCEP proposed a national cap on CO_2 emissions, which cuts national emissions intensity by 2.4-2.8% and caps costs at $7/ton of CO_2 with annual escalation at 5% annually. While it is, of course, difficult to determine if any Congressional action on climate is likely in the near or mid-term, Senator Bingaman (D-NM) has proposed inclusion of the NCEP cap-and-trade CO_2 provisions in the energy bill being debated in the Senate. It is PacifiCorp's best judgment that this effort will not move through Congress at this time, but that the NCEP proposal represents the current most likely provision to pass at a National level. While somewhat lower than our estimate, the Commission's cap of $7/ton is in line with the PacifiCorp base case assumption.

- While most utilities in the country are not formally considering carbon risk in planning, as noted by NWEC, several other utilities have recently adopted CO_2 adders since PacifiCorp became the first utility to do so in 2003. While the utilities cited by NWEC use slightly higher values, these developments in western utility regulation support the timing and magnitude of the PacifiCorp base case amount.

- The U.S. Energy Information Administration's analysis of the most recent cap-and-trade bill submitted by Senators McCain and Lieberman (which caps 2010 national emissions at 2000 levels and holds that level) shows CO_2 costs beginning at approximately $15/ton starting in 2010 and rising to $45/ton in 2034. The McCain-Lieberman provisions received 44 votes in the US Senate last year, but would need 60 to pass the Senate. Carbon constraints of this magnitude are not expected to be close to passing given the current make-up of the House. So while this analysis suggests passage of McCain-Lieberman could result in costs higher than PacifiCorp's base case assumptions, it is PacifiCorp's best judgment that McCain-Lieberman is not likely to pass in its current form and, therefore, that it is adequate to cover this potential policy outcome in the sensitivity runs required by Oregon and performed by PacifiCorp (up to $40/ton in 1990 dollars).

Added to these estimates is the obvious uncertainty associated with the arrival of greenhouse gas regulations at the federal and state levels. The values above are for regulations that are adopted and implemented by 2010. However, it is clear that political trends over the last year, at the federal level are not favoring the passage of greenhouse gas (GHG) legislation in the current Congress which runs through early 2007. This uncertainty translates into a probability of less than 1, which we must factor at least qualitatively when determining CO_2 values for planning and procurement purposes. When factored into the values above, our estimate of $8/ton is prudent for inclusion in the base case (as opposed to sensitivity analysis only) given available information on potential regulatory scenarios and current political trends.

PacifiCorp chooses to incorporate the carbon assumption into our base case analysis because we believe it is a prudent and necessary step for protecting our customers from future risks of carbon constraints. Using carbon as a base case assumption is not required, nor prohibited under the OPUC's 1993 order on incorporating carbon risk. PacifiCorp, of course, is committed to complying with the OPUC Order by performing the necessary CO_2 sensitivities ranging from $0 to $40/ton (1990 dollars) and has done so in this IRP.

Oregon-Specific CO_2 Regulatory Polices Not Adequately Considered

The second concern raised by parties is that PacifiCorp's analysis does not adequately consider the policy developments taking place in Oregon on the subject of climate change. The Oregon Governor did convene a Task Force to study the climate issue and to develop broad recommendations for the Governor's consideration. PacifiCorp participated in this Task Force process. The recommendation from the Task Force, regarding utility emissions, calls for a further group to be formed to consider methods to reduce utility emissions, including a possible load based cap.

In verbal and written comments to the Task Force, PacifiCorp has expressed its objection to a statewide load-based cap given that the methodology for imposing a statewide cap on a multi-state utility are (1) complex and (2) likely to be, costly, particularly when compliance costs would need to be segregated by state and paid for by Oregon customers. While depending on the nature of the cap, it clearly would be complex to segregate emission reductions that would arise from a wide variety of actions taken throughout the company. It would entail assigning all emissions across all states, as well as assigning emissions reductions across all states. Since

CO2 is so pervasive, many factors can drive CO2 emission increases and reductions. Isolating those factors for the purpose of cost recovery can be very challenging in many instances (e.g., hydro-electric availability, thermal plant outages, wind production--all will have an impact on overall CO2 emissions in our "business-as-usual" case; all costs associated with modifications of this business-as-usual case, such as altering plant usage, requiring additional market purchases, and other changes, would need to be quantified and segregated for payment by Oregon). Additionally, PacifiCorp might invest in efforts to reduce total CO2 emissions to meet a cap imposed by a single state. If these actions created co-benefits (e.g., added renewables generation that leads to benefits due to changes in gas prices) that benefit all customers, we would face conflicts between our states if implementation costs are borne entirely by one state.

Even if cost recovery issues were resolved so that one state cleanly bears all of the added costs associated with a cap, the anticipated costs of an aggressive cap on emissions by a single state are likely to be high. If a cap results in reduced generation from thermal generation or even plant closure, replacement resources would be required for which other states are unlikely to want to pay. While additional cost analysis is warranted to understand fully such costs, we are confident that the costs will be of concern to many stakeholders in Oregon.

No analysis has been performed by the state, as of yet, regarding the costs of such a load-based cap, and the group that will study mechanisms to address utility emissions has not yet been formed. PacifiCorp has committed to participating in the group once it is convened. In any case, since there have been no specific policy recommendations on CO2 regulation that are amenable to base case or even scenario analysis, it is too speculative to create a specific value based upon the Governor's Task Force at this time, or even to factor in an associated value when estimating the base case value.

Failure to Consider Alternative CO_2 Regulatory Scenarios and CO_2 Offset Availability

PacifiCorp believes that the best available information today points to air pollution regulatory regimes that institute national or regional caps and that encourage trading of emissions allowances to foster economic efficiency. Recent historical trends clearly point to this assumption, since the most significant developments in national air policy consist of cap-and-trade policies:

- The 1990 Amendments to the Clean Air Act, which instituted a national cap-and-trade regime for sulfur dioxide.
- The Clear Air Interstate Rule, which created a regional cap-and-trade regime in the East.
- The US EPA's recent mercury rulemaking, which creates a national cap-and-trade system.
- The Acid Rain program created in 1990 which, as the oldest such system, has seen program trading flourish with predictable changes in values associated with reduced caps over time, and hence higher demand among regulated entities for emissions allowances.

No specific assumptions have been made regarding the use of offsets in a future regulatory regime. PacifiCorp has substantial experience in the offset market and continues to monitor the market price of off-system reductions. The Climate Trust, with its experience in the offset world, continues to find high-quality offsets in the $2-$5/ton range. While this is useful information, the company recognizes the limitations of extrapolating from this offset price for future regulatory scenarios. The Climate Trust is operating in a pre-regulation market and one would expect regulation of CO_2 to change the supply and demand dynamics of the carbon market.

It is useful to consider a regulatory scenario without any emissions trading whatsoever in order to understand internal costs of CO_2 reduction. However, we believe it is not reasonable to assume no trading in a base case scenario for long-term resource planning.

URGENCY TO INVEST IN COAL PLANTS

Most of the parties assert that PacifiCorp's reliance on coal plants in the Preferred Portfolio, and the timing of the investments, present potentially greater cost risks than other resource options. Both CUB and NWEC stressed that, aside from the CO_2 mitigation cost implications, coal plants have substantial cost recovery risks characteristic of such large, long-term investments. They also stated that PacifiCorp failed to account for the value of deferring coal resource investment decisions given the uncertain regulatory, technology, and energy price prospects. Both ODOE and CUB noted that with a CO_2 cap in place, new coal plants could potentially force existing coal plants into retirement, thereby increasing costs to meet the load/resource gap. They stated that resources with little or no CO_2 cost risk, such as renewables and DSM, do not have this disadvantage. CUB further suggests that a Planning Margin lower than the 15-percent assumed for the IRP would be justified if it could help defer coal plants.

Finally, CUB asserts that PacifiCorp's IRP is "qualitatively skewed towards coal" by virtue of the Company's familiarity with coal resources and constituency pressures in Utah.

PacifiCorp's Response:

Since the parties cite a number of arguments to support their premise that PacifiCorp should avoid coal plant investments, the Company's response is organized into sections that address each one individually.

Coal Plant Cost Recovery Risks Not Adequately Considered

PacifiCorp agrees with the parties that large investments require long-term commitment, and that investing in a resource with a 40-year economic life does present risks related to changing market paradigms and policy developments. However, we expect that risks to cost recovery would be minimal given regulatory mechanisms—and the Multi-State Process—that are in place. PacifiCorp's past experience is that once the costs of a new generating unit are shown to be prudent, there are not serious future impediments to recovery of the costs in rates. In PacifiCorp's experience, rate recoverability of plant costs has been sufficiently certain and constant across the spectrum of plants in its portfolio that it would not materially affect a decision as to the type of plant to be built. We also note that long term resources of any type can mitigate cost, market, and reliability risks, as evidenced by the sensitivity analysis conducted for the IRP, which assessed the impact of gas price changes and key environmental policy changes in air quality and climate. Finally, PacifiCorp does not believe that commitment to a long-term resource of any type would preclude the Company from taking advantage of new technology developments, responding proactively to emerging policy developments, or adjusting its risk mitigation and procurement practices as needed to address changing market conditions. A variety of new resources will continue to be necessary to address load growth and planned resource retirements; changing market conditions and policy developments will inform the IRP Action Plan and consequent selection of new resources.

Failure to Account for the Value of Deferring Coal Investments

PacifiCorp believes that it has sufficiently captured the option value of the proxy generation resources by virtue of its stochastic risk analysis. Due primarily to forecasted gas price volatility, deferring a proxy coal plant actually increases overall portfolio risk as indicated by the various stochastic risk measures. Thus the question of whether there is value to be gained by deferring coal investments has been studied. Reasonable uncertainties surrounding use of coal have been taken into account. Giving recognition to coal costs inclusive of costs of future uncertainties did not shift sufficient value to a coal plant deferral scenario to alter the outcome of the analysis. PacifiCorp also conducted a deterministic sensitivity analysis of the cost-effectiveness of substituting a coal plant with a CCCT unit. (See the "Resource Build Sequence" portfolio comparison results on pages 118-119 of the IRP). This analysis indicated that there was no economic benefit from deferring a coal plant.

Regarding the parties' contention that PacifiCorp should postpone a coal plant decision and acquire alternative resources, PacifiCorp reiterates its need to take prompt and focused steps to address the growing gap between its obligations and resources. Procurement of the resources identified in the IRP needs to happen concurrently with additional study of alternative resource options—and without delay—in order to close this gap. Waiting for renewables, demand-side options, and distributed generation resources to be fully explored before consideration of the thermal resources identified in the Action Plan would imprudently impact PacifiCorp's ability to supply reliable, low cost power to its customers. We also stress that PacifiCorp will conduct a then-current view of all relevant resource options and markets when developing the procurement strategy for a required resource. Using a coal-fired plant as a proxy high-capacity-factor resource in the IRP Preferred Portfolio does not preclude PacifiCorp from considering other alternatives if those alternatives make sense from economic, risk management, and system reliability perspectives.

Failure to Consider Impacts of a Firm Cap on CO2

ODOE and CUB's assertion that a firm cap on CO2 emissions could force the retirement of older coal plants presumes a specific architecture of a future CO2 cap. Specifically, it assumes a firm CO2 cap without trading and a baseline set at current emissions levels. PacifiCorp believes it is too early to know what type of CO2 regulatory regime might ultimately develop, much less the specific architecture of that regime. For that reason, the IRP uses an $8/ton CO2 allowance cost as a proxy to reflect a multitude of possible future CO2 regulatory scenarios. As discussed above, PacifiCorp believes the best available information points to a regulatory regime that would include trading with the imposition of a firm cap.

We also disagree with CUB's interpretation of PacifiCorp's response to a CUB data request. Specifically, CUB asserts in their comments that "PacifiCorp agrees that, if the new [coal] plant displaced a less efficient [coal] plant, we would not have advanced the ball very far." (CUB comments, pages 16-7). PacifiCorp expressed no such view in its response to CUB's data request. CUB's interpretation of our data response implies that we see little benefit to replacing an older, dirtier resource with a cleaner one. In fact, we simply affirmed that any resource replacing a retired one would go through PacifiCorp's normal IRP and procurement processes. Our view is that planned retirement of existing plants and replacement with newer coal plants could not only result in a net emissions reduction, but also offer the potential to avoid costs necessary to keep older units running, thereby minimizing the costs to meet the load/resource gap.

Consideration of a Lower Planning Margin to Avoid Coal Plant Investment

Changing the Planning Margin with the narrow view of avoiding investment in one type of technology or fuel type is not appropriate, particularly when the IRP does not dictate what the technology or fuel type should be. (That is determined from the outcome of the procurement process).

PacifiCorp's decision to adopt a system-wide 15% Planning Margin was well-informed by both physical and economic resource adequacy perspectives. The decision methodically took into consideration the following factors:

- The Company's obligation to provide reliable, low-cost electricity service to customers
- WECC reserve requirements
- A stochastic system dispatch analysis of Planning Margin impacts on system reliability (described in great detail in Appendix N of the IRP Technical Appendix)
- Cost/risk trade-off analysis for various Planning Margin levels (also documented in Appendix N)
- Deterministic system simulations of portfolios based on alternative Planning Margin levels (12% and 18% stress cases)
- Economic implications of physical short exposure to markets
- Industry standard reliability thresholds, and planning margin assumptions made by other Western utilities

The Planning Margin level adopted therefore represents an optimal result stemming from the Company's long-term system planning perspective and a balanced view concerning reliability and economic consequences.

While the merit of planning to a lower margin is a germane topic, it would need to be further explored at regional and state public policy levels, and account for the resource adequacy standards now being formulated by a number of regional organizations. Until the picture concerning resource adequacy standards and coordination becomes sufficiently clear, there is no compelling reason for PacifiCorp to deviate from its current practice in determining the optimal Planning Margin.

The IRP is Qualitatively Skewed Towards Coal

PacifiCorp strongly disagrees that its IRP is skewed toward coal, and finds this accusation an instructive example of the stakeholder conflicts the Company faces in the IRP process.

The Preferred Portfolio, which outlines the need to acquire a range of supply and demand-side resources—gas, coal, DSM, shaped purchases, and renewables—was developed via a rigorous analytical process documented in an open, public forum. The quantitative results, informed by PacifiCorp's resource planning experience and expert judgment, determined the type and timing of thermal resources in the Preferred Portfolio, not constituency pressure.

PacifiCorp finds the accusation instructive because some parties would assert just the opposite, that PacifiCorp is skewed toward gas resources by virtue of its gas-fired Currant Creek and Lake Side projects, and that 64% (1,691 MW) of the Preferred Portfolio's new thermal resources are gas. As discussed above, the IRP risk analysis clearly shows that the best portfolio to meet PacifiCorp's growing resource needs is not one "skewed" toward a specific thermal resource type, but a diverse portfolio of supply and demand-side resources that includes gas, coal, DSM, shaped purchases and renewables.

ADEQUACY OF RISK ANALYSIS FOR COAL VERSUS GAS-FIRED RESOURCES

Two parties—ODOE and CUB—claim that PacifiCorp's risk analysis was deficient in that it did not directly weigh CO_2 cost risk against gas price risk either as part of the stochastic risk analysis or scenario risk analysis. As a result, the Company did not prove that the Preferred Portfolio—with its two proxy coal resources—was preferable to an "all-gas" portfolio (such as Portfolio M) or a renewables-intensive portfolio.

PacifiCorp's Response:

Both ODOE and CUB presume that PacifiCorp's selection of the Preferred Portfolio can be distilled down to a simple comparison of extreme CO_2 regulation and gas price risks. This is simply not the case. Further, they claim that these extreme risks were not evaluated on a consistent basis— either as part of stochastic analysis or Scenario Risk analysis. In addition to clarifying the role of risk analysis in selecting the Preferred Portfolio, we explain below why comparing CO_2 regulation and gas price risks using the same risk analysis technique is not appropriate given the disparate characteristics of these risks.

PacifiCorp's risk analysis consisted of a wide variety of risk measures, including (1) multiple stochastic-based cost, variance, cost-risk tradeoff, and statistical significance metrics, and (2) deterministic cost results from Scenario Risk simulation runs. PacifiCorp did not rely on a single or small subset of risk metrics to inform the portfolio selection process; rather, it composed a qualitative assessment of risk using all available measures. We view this approach as not only appropriate, but necessary given the uncertainties and difficulties in measuring resource portfolio risks, and an insufficient basis to quantitatively weight the decision value of each risk metric.

We emphasize that the stochastic analysis results were not used to exclude portfolios characterized as "gas-intensive" or "coal-intensive" from the Scenario Risk analysis phase, or to judge overall superiority of one portfolio against another, such as E versus M. We stated, on page 154 of the IRP that the main conclusion of the stochastic analysis was that "generally portfolios with fuel diversity in capacity additions and associated generation exhibited less risk than those that did not, i.e., portfolios with heavy reliance on additional gas capacity." Although Portfolio M did not do well in the stochastic analysis because of gas price volatility impacts, it was nevertheless selected for Scenario Risk analysis because of its favorable deterministic PVRR outcome.

Concerning the role of Scenario Risk analysis, its purpose was to inform the portfolio selection process by indicating cost implications of alternative futures. Recall from page 62 of the IRP that the risk scenarios examined do not presuppose a probability of occurrence. Consequently, cost magnitudes indicated by the Scenario Risk analyses cannot be used to determine the comparative riskiness of the scenarios. If probabilities of occurrence could be assigned with any degree of confidence, then PacifiCorp would have indeed conducted "a complete *stochastic* analysis on the full range of CO2 adders and natural gas prices," as mentioned by ODOE. In summary, the nature of the risks evaluated and the limitations of the Scenario Risk analysis technique dictated that its appropriate use was to indicate which portfolios would experience large cost deviations from expected values under high CO_2 and gas cost conditions; using inferences concerning the relative sizes of the deviations to select portfolios is not considered appropriate.

Regarding the final selection of Preferred Portfolio candidates, the conclusion of PacifiCorp's overall risk analysis was that an optimal portfolio, from a risk reduction perspective, would need to avoid resource mixes characterized by heavy dependence on a particular fuel type—coal or gas—or a particular generation technology. Portfolios E (the Preferred Portfolio) and K best met that criterion. The fact that certain portfolios deviated greatly from Portfolios E and K with respect to cost performance under the Scenario Risk assumptions guided PacifiCorp's decision to rule them out as Preferred Portfolio candidates.

Finally, the exclusion of both Portfolio M and coal-intensive Portfolio Q as Preferred Portfolio candidates illustrates that the high gas price scenario was not given more weight than the CO_2 cost scenarios; Portfolio Q did well on many stochastic metrics, but was nevertheless excluded by virtue of its poorer relative showing under higher CO_2 allowance cost levels.

INADEQUATE CONSIDERATION OF RENEWABLE RESOURCES

While parties generally supported PacifiCorp's efforts to improve the modeling of wind resources, most of the parties cited alleged deficiencies in the treatment of wind resources for portfolio analysis. The most serious concern was that PacifiCorp underestimated the potential contribution of renewable resources by purportedly failing to consider an expanded renewable resource base beyond the 1,400 MW target identified in the Action Plan, as well as portfolios with additional renewable resources. Specific issues identified included the following:

- ODOE noted that PacifiCorp lags behind other Western utilities concerning renewable resource targets, citing such utilities as San Diego Gas and Electric, Nevada Power, Puget Sound Energy, Idaho Power, and Pacific Gas & Electric. RNP also asserts that PacifiCorp should have a higher renewables target.

- ODOE and NWEC pointed out issues with PacifiCorp's interpretation and use of its renewables supply curve to support the 1,400 MW renewables target. (Appendix J of the IRP Technical Appendix, pages 144-7). ODOE thought the supply curve should have accounted for greater renewable MW participation in future RFPs due to improving cost trends, as well as CO_2 cost and gas price risk reduction. NWEC stated that the "flatness" of the curve is evidence that the magnitude of cost-effective wind is sensitive to assumptions, and that PacifiCorp should have therefore performed risk and stress case analysis for scenarios based on additional renewable resources.

- ODOE, CUB, and NWEC claimed that PacifiCorp failed to consider the implications of the Preferred Portfolio on wind integration costs, pointing to the observation that coal resources are less able to provide shaping support for wind than flexible gas-fired resources.

- A number of parties cited the lack of progress with the Renewables RFP.

PacifiCorp's Response:

Since the parties cited a number of arguments to support their premise that PacifiCorp should have done more renewables analysis as part of the portfolio evaluation, the Company's response is organized into sections that address each concern individually.

PacifiCorp's Renewable Target Lags Behind Other Utilities

According to a draft report from Lawrence Berkeley National Laboratory, PacifiCorp's modeled amount of renewable generation is much higher than all other utilities in the region. The resulting portion of renewables in our final portfolio by 2014 is roughly equivalent, on an energy basis, to the total *combined* renewables generation in the final portfolios of Puget Sound Energy, Idaho Power, Portland General Electric, and Avista (Mark Bolinger and Ryan Wiser, 2005, as cited by Virinder Singh in presentation at Windpower 2005, May 17, 2005, Denver, Colorado).

Inadequate Capturing of Coal Resource Impacts on Wind Integration Costs

The IRP model captures the wind-related incremental system dispatch (or "imbalance") cost impacts across different resource portfolios. It does this by virtue of the model's thermal plant commitment and economic dispatch decisions given the presence of fully-dispatched wind resources. The model includes minimum-up, minimum-down, and ramp rate data by generating unit. A simulation will therefore implicitly capture any system cost impacts attributable to renewables in the resource mix. We note that the estimation of imbalance costs associated with integrating wind projects can be improved by modeling wind output stochastically. Currently, wind output is set to fixed hourly MW limits in the MarketSym/ProSym model. PacifiCorp is investigating this potential modeling improvement for the next IRP.

We also note that while resources with dynamic "regulating reserve" capability are necessary to accommodate wind on a power system, it is not necessary for all resources to have that capability. PacifiCorp expects to have sufficient regulating reserve resources to be able to accommodate the projected wind additions regardless of the quantity and fuel type (coal or natural gas) of base load resources added to the system.

Renewable Supply Curve Deficiencies and Analysis Conclusions

While the supply curve does not indicate that 1,400 MW is a hard upper limit on cost effectiveness, it does show the 1,400 MW target could reasonably be expected to be cost effective. PacifiCorp has made clear that 1,400 MW should remain the planning target until additional experience with substantial amounts of wind on the system is obtained, and methods for estimating integration costs are improved. On page 145 of the 2004 IRP Technical Appendix, PacifiCorp provides a supply curve which depicts the cumulative results from the bids received in RFP 2003-B. The supply curve shows that 1,400 MW is not an unreasonable expectation for renewable resource availability in and around the PacifiCorp service territory.

PacifiCorp also notes that the supply curve necessarily represents a snapshot in time. Since the supply curve was produced, wind turbine prices have increased substantially due to worldwide competition for limited manufacturing capability, weak dollar on foreign currency markets, and higher steel prices. Nevertheless, wind turbine technology may continue to improve on availability, efficiency, and size. PacifiCorp is committed to procuring resources ahead of the planned schedule, if it is economic to do so. The IRP Action Plan allows the necessary flexibility to substantially increase the ultimate level of procurement over the full ten-year period, should the economics of wind projects become more favorable for doing so.

Lack of Progress on the Renewables RFP

PacifiCorp's efforts to acquire renewable resources face some substantial hurdles, including: (1) short and undependable extensions of the federal renewable resource production tax credit; (2) rising wind turbine prices due to higher steel prices and a weak dollar in relation to foreign currencies and (3) the lack of available turbines. Despite these considerable obstacles, PacifiCorp has signed a long-term power purchase agreement for a 64.5 MW wind project to be constructed in 2005, and remains optimistic about the prospects for meeting the 2006 targets, assuming that the production tax credit extension passes into law by the end of 2005. PacifiCorp supports an early extension for multiple years, and actively lobbies on its behalf. Negotiations with RFP bidders continue despite present uncertainty over the production tax credit.

DSM OPPORTUNITIES

A number of parties stress the importance of DSM in PacifiCorp's Preferred Portfolio, and urge the Company to be more aggressive in pursuing DSM opportunities to address the Utah peak-load problem and augment a more renewables-intensive resource strategy. CUB expressed its frustration that PacifiCorp only now seems to be serious about addressing Utah's load growth, even though the Company has projected high peak-load growth rates for a decade. ODOE commented that PacifiCorp did not consider a "serious" interruptible load program to assure system reliability. NWEC criticized PacifiCorp for not fully capturing the environmental regulatory and fuel price risk reduction benefits of energy efficiency programs in the portfolio analysis.

PacifiCorp's Response:

The Company is aggressively pursuing DSM. There has been a 60% increase in Class 2 acquisition from 2002 (15.4 MWa) to the current FY2006 goal (24.8 MWa, including Energy Trust of Oregon). This growth has occurred primarily in Utah. The 2005 DSM RFP will include even more Class 2 DSM. In addition, Class 1 resources have grown from nothing in 2002 to over 90 MW in the summer of 2005, in the East system. PacifiCorp has plans to increase this level to over 150 MW of Class 1 by 2008. The IRP Action Plan includes even a larger build-out of Class 1. In addition, PacifiCorp has 261 MW of individual customer curtailment agreements in place for the East System. The net peak effect of DSM over the next 10 years is:

125 MW Class 1 DSM base case (Cool Keeper, ID Irrigation load control)
177 MW new Class 1 programs in IRP Action Plan
323 MW of Class 2 resources (peak effect of 250 MWa in base case)
<u>261 MW</u> of individual customer contracts
886 MW Total peak reduction due to DSM in the Company's current plans

NWEC stated that by virtue of conducting risk analysis prior to performing the DSM decrement analysis, PacifiCorp failed to fully capture the value of energy efficiency programs for reducing fuel price and environment regulatory risks. For Class 2 DSM, PacifiCorp followed the general guidelines for decrement analysis as described by the Tellus Institute in their report, "Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities" completed in September, 1995. Sections II.2.A and II.2B discuss the ideal decrement analysis and why there are practical limitations to conducting this analysis on a program opportunity by program opportunity basis. The methodology used does capture the value of fuel and pollutant reduction values for a large block of potential DSM. Small blocks of DSM may not capture these values, as they may be too small to register a change in PVRR.

OTHER COMMENTS

The remainder of this document outlines various issues and concerns, raised by parties, that are not directly tied to recommendations for Commission acknowledgement of PacifiCorp's IRP or specific resources.

Integrated Gasification Combined Cycle Resources

The parties that addressed Integrated Gasification Combined Cycle (IGCC) resources suggest that the technology has merit as a viable resource choice for the IRP, but only after renewables and other options are fully explored and utilized. CUB cited technology and stranded-cost risks as sufficient motivation to postpone consideration of IGCC until the technology matures, while NWEC stated that prospects for cost-cutting advancements and economic incentives for IGCC technologies, along with numerous planning uncertainties surrounding coal plant investment, "are not well-accounted for in the Company's analysis." ODOE advocated further site-specific analysis of the Hunter site to refine a cost breakeven point for IGCC with sequestration versus pulverized coal.

PacifiCorp's Response:

PacifiCorp acknowledges that the outlook for IGCC is evolving rapidly as commercialization efforts gain momentum and electric utility experience with the technology progresses. In light of the changing and emerging IGCC picture, PacifiCorp continues to investigate the application of IGCC technology in the PacifiCorp system. Although the IGCC cost estimates relative to conventional coal may be higher than some published reports, PacifiCorp believes the conservative approach used for the 2004 IRP approximates the probable risk of an IGCC application in the PacifiCorp service area due to such factors as site elevation, new technology, local labor costs, and probable coal resources. PacifiCorp points out that the IRP's IGCC cost estimates are based on numerous studies conducted over the last few years by various organizations including EPRI and the US Department of Energy. The estimates also incorporated the operating experience of the Polk and Wabash River IGCC plants.

Since the publication of the 2004 IRP, PacifiCorp has contracted with Parsons E&C to conduct a site specific study to understand the cost impacts of installing an IGCC utilizing Utah coal and operating at elevation. The results from this study will be incorporated into the next resource planning process.

Hydroelectric Resources

HRC-WW commended PacifiCorp's determinations to remove certain dams, and supported the choice not to select a pumped storage hydro plant as part of the Preferred Portfolio. However, it had a number of criticisms relating to PacifiCorp's statements concerning hydropower resource policies and licensing processes, as well as data reporting. These comments are as follows:

Relicensing Policies and Process

- HRC-WW disagrees with PacifiCorp's assertion that licensing takes five and generally 10 years, and points to the financial benefits that accrue as a result of an extended relicensing process.

- HRC-WW disagrees with PacifiCorp's characterization that "agencies' interests may compete or conflict with each other leading to potentially contrary, or additive, licensing requirements." It further states that "The narrative also appears to blame agencies and our environmental laws for associated license costs when rather, it is simply the cost of doing business."

- HRC-WW takes offense with PacifiCorp's depiction of Federal Power Act reform efforts as a progressive action, citing extensive opposition to the legislation by non-utility stakeholder groups.

- HRC-WW claims that PacifiCorp's statement that plant modifications required by FERC can greatly reduce the electricity value of projects runs counter to licensing results in practice.

Data Reporting

- HRC-WW seeks clarification on why PacifiCorp reports hydropower capacity expansion with an accompanying decline in forecasted generation.

- PacifiCorp's relicensing data reported in Appendix C, Table C.23 of the Technical Appendix is claimed to be out of date. In addition, for future IRPs, HRC-WW recommends that the Company report any plans to continue operation for hydropower assets that have estimated retirement dates within the 20-year IRP study period, and to consider the probability of dam removal on expected life expectancy.

Hydro Endowment

- HRC-WW supports the idea of developing a hydro endowment. HRC-WW states that an endowment could provide an excellent way to isolate expenditures and ensure that capital is available for facility enhancements under the typical investment income endowment structure.

PacifiCorp's Response:

HRC-WW's comments, as outlined above, are addressed in order.

Licensing Duration

PacifiCorp's statement, about the length of time required for licensing, is correct. While the Federal Power Act may envision a licensing process of five years, the reality is that many projects take far longer. In fact, relicensing of the Cushman hydroelectric project, owned by Tacoma City Light, has been ongoing for nearly 30 years. The FERC itself recognized that the relicensing process was too time-consuming and costly. As a result, FERC issued a Notice of Proposed Rulemaking on February 21, 2003, with the express purpose of developing a streamlined relicensing process as an alternative to the traditional relicensing process. In its rulemaking FERC noted that:

> Many factors can cause delays in licensing. These include multiple applications for projects in the same watershed; failure to resolve during pre-filing consultation disagreements over requests for the applicant to gather information or conduct studies; requests for extensions of time, including extensions of time for Federal agencies to provide mandatory conditions pursuant to FPA Section 4(e) and fishway prescriptions pursuant to Section 18, or required consultation with the U.S. Fish and Wildlife Service or National Marine Fisheries Service (NMFS) and attendant studies under the [Endangered Species Act] ESA; and delayed receipt of state water quality certification. Some or all of these factors may be present in any license proceeding. However, the principal causes of delay are the need for additional information or studies after the application is filed, untimely receipt of biological opinions under the ESA, and state water quality certification.

In our experience and in that of many other licensees, the more complex the project in terms of its geographic location, operations and resource issues, the longer the process can take. This is only logical: more information is needed to evaluate project impacts and benefits and develop mitigation proposals, in addition to the ESA and other issues found in more complicated relicensings.

Further, in its final rule issued on July 23, 2003 adopting the "Integrated Licensing Process", FERC noted that while the traditional licensing process can work, only one-third of projects in traditional licensing were issued new licenses prior to license expiration. This indicates that two-thirds of project relicensings were taking over five years to complete. (Final Rule, Order No. 2002, July 23, 2003, page 7, no. 21).

Finally, PacifiCorp's own experience is that licensing takes far longer than desired or envisioned under the Federal Power Act. Some examples of extended relicensing timelines include the following:

- Condit, White Salmon River, Washington – 14 years, the process is still ongoing.
- North Umpqua, North Umpqua River, Oregon – 13 years before license was issued; litigation continues.
- Powerdale, Hood River, Oregon – 10 years awaiting FERC Order.

Conflicting Agency Interests

PacifiCorp disagrees with HRC-WW's assertion that agency conditions "rarely conflict." Rather, it would be an exceptional process where such conflicts do not arise. To provide a practical example of such agency conflicts, federal mandates to protect anadromous fish under the ESA directly conflict with both federal and state fishery agency mandates and regulations, as well as tribal policies to promote commercial harvest of such species. Further where ESA species exist in the same project area, conflicts often arise. For instance, the reintroduction of anadromous salmon into reservoirs behind dams can adversely affect ESA-listed resident fish such as bull trout. Water quality conditions can be imposed to benefit one species to the detriment of other species. Numerous other examples exist. It is exactly these types of conflicts that must be approached very thoughtfully and carefully in the relicensing process, and, as a result, can lead to delays in the process.

Regarding HRC-WW's comment on PacifiCorp's alleged assignment of blame for relicensing costs, it is not PacifiCorp's intent to "blame" agencies or laws for license costs or to suggest that they are inappropriate. The sole intent is to provide factual information. It is a fact that these laws and regulations are intended to protect the public interest. It is also a fact that these laws and regulations, particularly with respect to how they are interpreted and applied, do add costs to the licensing process and operations.

Depiction of Federal Power Act Reform Efforts

In its comments, HRC-WW states that "every non-utility stakeholder in the licensing process opposes the reform to the Federal Power Act." (HRC-WW comments, page 3). PacifiCorp believes this is an overstatement. While it is true that many interests oppose reform of the Federal Power Act, many others support reform. PacifiCorp's position is that relicensing is intended to result in an appropriate balance between meeting today's environmental standards while providing customer benefits in the form of reliable, renewable generation. The legislative reform being proposed would allow licensees to bring forward project mitigation "alternatives" to agency mandated conditions so long as they would: (1) provide greater operational efficiencies; and, (2) provide the same level of environmental protection. We believe such an approach is in both the customers' and the environment's best interests. We also believe that other interests or stakeholders in the relicensing process should be able to bring forth such proposals, so long as they meet those same criteria.

Reduction in Electricity Value from Plant Modifications

It is clear, from a relicensing perspective, that generation has and will decline as a result of new operational constraints imposed in new FERC licenses. For example, as part of relicensing the North Umpqua project, the company agreed to new operational constraints that effectively result in a generation loss of 8 percent. Project decommissioning in the next few years also will result in a loss of approximately 22 megawatts of capacity as these projects are taken off-line and are no longer in the company's generation mix.

Explanation of Why Hydro Capacity is Increasing While Generation is Decreasing

Overall, PacifiCorp's hydro resources are declining over the next few years as several small plants are being decommissioned because the conditions of relicensing or the costs of refurbishment have made the projects uneconomic. The exception is the hydro capacity coming back online due to the reconstruction of the Swift 2 hydro plant that was destroyed in the catastrophic canal failure in April 2001. While the Swift 2 hydro plant is expected to be commercial on March 1, 2006, PacifiCorp does not expect a corresponding increase in generation due to an offsetting contractual obligation.

Appendix C Relicensing Data is Out of Date

The table below shows the latest information on project licensing status (as of March 2005). The table indicates which projects are expected to be issued Surrender Orders for project decommissioning, with the exception of the Bear River project's Cove facility. A filing has not yet been made with FERC with respect to this facility.

Project	State	MWs	Status
1. North Umpqua – 8 dams/plants, N.Umpua River	Oregon	185	**Settlement in 1999, license issued 2003**, license being appealed, final order expected Spring 2006, some implementation ongoing.
2. Bear River – 3 dams, 7 plants, Bear River	Idaho	116	**Settlement reached 2002, license issued 2003,** implementation ongoing.
3. Big Fork	Montana	4	**License issued 2003.**
4. American Fork	Utah	1	**Decommissioning agreement reached 2003, Surrender Order issued 2004.**
5. Condit – 1 dam, plant	Wash.	14.7	**Decommissioning settlement 1999**, amended 2/2005, permitting ongoing, **Surrender Order expected 2008**
6. Lewis River, - 3 Pacificorp dams/plants + 1 CPUD, Lewis River	Wash.	510	**Settlement November 2004**, draft BAs to FERC 1/2005, 401 certification submitted 2/2005, **license expected 4/2006**
7. Powerdale - Hood River, 1 dam/plant	Oregon	6.5	**Decommissioning settlement submitted 2003**, 401 issued, Biological Opinions pending, final Surrender Order 2005.
8. Prospect 1,2,4 - Rogue River, 3 dams/plants	Oregon	41.5	**Submitted license June 2003**, 401 permit application filed, **final license expected 2005.**
9. Klamath – 7 dams/plants Klamath River	Oregon	151	**Final license application submitted March 2004**, settlement ongoing, **license expires 3/2006**

Regarding dam removal, the company's position is that we are willing to consider removal if it can be shown to be the best outcome for our customers compared to the relicensing alternatives.

Clarification of Hydro Endowment

WaterWatch refers to the "hydro endowment" contained in the Company's interjurisdictional allocation method (Revised Protocol). The "hydro endowment" is not a "typical investment-income endowment structure" as suggested by WaterWatch. The "hydro endowment", referred to on page 39 of the IRP, is a cost allocation method that "more directly assigns the costs of company-owned hydroelectric resources and, to a substantial extent, hydro-based contracts with the Mid-Columbia utilities to the former Pacific Power states". The Revised Protocol, including a description of how the cost of hydroelectric resources and Mid-Columbia contracts are allocated among PacifiCorp's jurisdictions, is in Order No. 05-021 (UM 1050), which was issued by the Oregon Commission on January 12, 2005.

Distributed Generation Resources

NWEC states that PacifiCorp should investigate the use of solar photovoltaic projects to address Salt Lake City peak load, and cited a study submitted as testimony that claimed that solar PV can be cost-effective for this purpose. NWEC also urges PacifiCorp to conduct more detailed modeling of CHP options in future IRPs.

PacifiCorp's Response:

In an IRP modeling context, the large capital cost associated with solar resources would clearly result in a relatively uneconomic outcome for portfolios with significant PV solar resources. (Solar costs are noted on the Supply-Side Options table in the 2004 IRP Technical Appendix on page 65.) States that are implementing distributed solar PV programs appear to be doing so as a matter of public policy, not as a least-cost resource.

Regarding CHP modeling, PacifiCorp welcomes specific suggested improvements in modeling CHP for future IRP's. General comments that modeling needs to be improved, do not give the Company enough information to evaluate the merits of such a suggestion. An issue that needs to be considered in any proposed modeling suggestion is that these units are sited based on customer economics and opportunity. QFs come in at avoided costs. A plant that otherwise qualifies as a QF can also bid into a supply-side RFP and get the capacity pricing received, if the bid wins.