ORDER NO. 10-066
ENTERED 02/24/10

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 47

In the Matter of PACIFICORP 2008 Integrated Resource Plan.	ORDER

DISPOSITION: MODIFIED PLAN ACKNOWLEDGED WITH AN EXCEPTION

INTRODUCTION

PacifiCorp, dba PacifiCorp & Light Company (PacifiCorp or the Company) seeks acknowledgement of its 2008 Integrated Resource Plan (IRP). This filing is in accordance with Public Utility Commission of Oregon (Commission) Order No. 07-002, as corrected by Order No. 07-047 requiring all regulated energy utilities operating in Oregon to engage in integrated resource planning. [1]

We acknowledge the Plan, as it has been modified during this docket, with one exception. We also identify several requirements for PacifiCorp's next planning cycle.

Requirements for Integrated Resource Planning

The Commission requires regulated energy utilities to prepare integrated resource plans within two years of acknowledgment of their last plans. Utilities must involve the Commission and the public both in their planning process and prior to resource decisions being made. In an integrated resource plan, an energy utility must: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) aim to select a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies. *See* Order No. 07-002.

The Commission acknowledges resource plans that satisfy procedural and substantive requirements, and that are deemed reasonable at the time of acknowledgment.

[1] The Commission originally adopted least-cost planning in Order No. 89-507 (Docket UM 180). The Commission updated the utility planning process in Docket UM 1056, in which Order Nos. 07-002 and 07-047 were entered.

PacifiCorp's 2008 IRP

PacifiCorp filed its 2008 IRP on May 29, 2009. The Company had previously filed a draft IRP for public review and comment on April 8, 2009. PacifiCorp presented its 2008 IRP to the Commission at the Public Meeting on September 8, 2009. On October 8, 2009, Staff and Parties[2] filed Opening Comments. PacifiCorp filed Reply Comments on November 3, 2009. Staff filed Final Comments on December 8, 2009. On January 7, 2010, PacifiCorp and Intervenors filed Reply Comments. Staff presented its Draft Order to the Commission at the Public Meeting on February 2, 2010. The Commission acknowledged PacifiCorp's modified 2008 IRP with one exception.

The Company projects that its rate of growth in energy and capacity will decline, as compared to historical averages, due to the impact of the housing market slowdown and economic recession. Based on a November 2008 load forecast, PacifiCorp projects that its system will become short on capacity in 2011, and on an energy basis, the system begins to experience a short position by 2012.

PacifiCorp developed 57 resource portfolios using a capacity expansion model (CEM) that optimizes a resource portfolio to meet energy and capacity needs based on a variety of input assumptions and capacity planning criteria. Using a production cost model (PAR), the Company simulated the performance of these portfolios with stochastic variation in key variables. These stochastic variables include loads, natural gas prices, wholesale electricity prices, hydroelectric generation and thermal resource availability. The Company weights seven measures to identify the top-performing portfolios. The three measures given the most weight for scoring portfolios are: (1) Risk-adjusted Present Value of Revenue Requirement (PVRR) (45 percent weight); (2) Customer rate impact[3] (20 percent weight); and (3) Carbon dioxide cost exposure[4] (15 percent weight). PacifiCorp focused its final portfolio performance evaluation on the four portfolios with the best performance scores.

In contrast to its 2007 IRP, the Company faced additional planning uncertainties in the development of its 2008 IRP due to the current economic recession and a significant decline in industrial and commercial sector demand. This reduction in demand is projected to translate into a near-term reduction in resource need. At the same time, the depth of the economic recession and the pace of a recovery are uncertain. Prompted by the severe decline in actual loads through January 2009, PacifiCorp prepared two forecasts: its original forecast from November 2008 and an additional forecast in February 2009. The February 2009 load forecast did not change the year in which PacifiCorp becomes capacity deficient. Using the preferred portfolio, the Company conducted additional sensitivity

[2] The following parties intervened: the Oregon Department of Energy (ODOE); the Citizens' Utility Board of Oregon (CUB); the Renewable Northwest Project (RNP); the Industrial Customers of Northwest Utilities (ICNU); and Portland General Electric Company (PGE).

[3] The customer rate impact is the average annual change in the customer $/MWh price for the period 2010 through 2018.

[4] The carbon dioxide cost exposure reflects a portfolio's potential for avoiding worst-case cost outcomes given CO_2 regulatory cost uncertainty.

analyses using the February 2009 load forecast. The Company concluded that there were no significant changes in its recommended near-term acquisition strategy.

Implementation Actions for PacifiCorp's Preferred Resource Strategy

Based on the analysis described later, PacifiCorp selected Portfolio 5B_CCCT_Wet as its preferred course of action. The Company recommends the following resource actions for 2009 to 2018 (Action Plan):

- Build or acquire 1,400 megawatts (MW) of renewable resources by 2018, including 393 MW of wind resources expected to be on-line by year-end 2010
- Acquire up to 1,400 MW of front office transactions on an annual basis as needed through 2013
- Procure a 570 MW Utah wet-cooled gas combined-cycle combustion turbine (CCCT) that would potentially be on-line by the summer of 2014
- Procure a 261 MW east-side intercooled aeroderivative simple-cycle gas plant (SCCT) that would potentially be on-line by the summer of 2016
- Complete coal-fired power plant efficiency improvements which are expected to add 128 MW in the east and 42 MW in the west with zero incremental emissions
- Pursue 200 MW of additional savings from expanded Utah Cool Keeper program participation by 2018 and 130 MW of additional class 1 Demand-side Management (DSM)
- Acquire 900-1,000 MW of cost-effective Class 2 programs by 2018 (peak capacity), equivalent to about 430 to 480 MWa
- Pursue 100 MW of distributed generation resources by 2018
- In 2009-2011, obtain Certificates of Public Convenience and Necessity for Utah/Wyoming/Northwest segments of the Energy Gateway Transmission Project
- In 2010, permit and construct a 345 kV line between Populus to Terminal
- In 2012, permit and construct a 500 kV line between Mona and Oquirrh
- In 2014, permit and construct a 230 kV line between Windstar and Populus and permit and construct a 345 kV line between Sigurd and Red Butte
- In 2016, permit and construct a 500 kV line between Populous and Hemingway
- In 2017, permit and construct a 500 kV line between Aeolus and Mona

The Company requests acknowledgment of its recommended Action Plan to implement its preferred portfolio of resources. The Action Plan includes activities for decisions the Company intends to make in the next one to ten years. PacifiCorp states that the Commission should not rigidly review the preferred portfolio selected resource types or acquisition time periods, but should, instead, recognize that in the IRP are proxy resources representing the fuel type, operating characteristics, and time frames that PacifiCorp deems to best fit the deficit position at the time that the IRP was prepared; actual resource types and timing will be determined during the procurement process.

PacifiCorp issued a request to resume its 2008 Request for Proposals (RFP) in fulfillment of Action Item 3, or the third bullet listed above. The Commission approved that request with conditions. *See* Docket UM 1360. The Company plans to issue an RFP at a later date for acquiring additional renewable resources.

Parties' Recommendations

In its Final Comments, Staff identified as a primary concern, the impact of the current economic climate and declining load on the timing and type of resource selection in the preferred portfolio. The Company responded to Staff's concerns about the need for and timing of new combined cycle and single cycle combustion turbines by stating that it will update its portfolios analyses as part of its 2008 all-source RFP (*See* Docket UM 1360) and in the 2008 IRP update.

Based on PacifiCorp's additional analysis, Staff supported acknowledgement of PacifiCorp's proposed transmission actions. RNP and CUB also indicated that building new transmission capacity will decrease wind integration costs and benefit Oregon customers over the entire life of the asset. PacifiCorp, RNP, and CUB supported Staff's recommendation for additional analyses of transmission options in future IRPs.

RNP, CUB, NWEC and Staff all criticized the Company's wind integration analysis. RNP and CUB argued that PacifiCorp did not take into consideration the interplay of load and wind variability. RNP and CUB claimed that on an actual basis, load variability and wind variability will offset, thereby reducing reserve requirements and leading to lower costs of integration. RNP and CUB also argued that: (1) PacifiCorp's representation of wind generation from new wind projects significantly overstates reserve requirements; (2) the Company incorrectly assumes that all inter-hour balancing is done through market transactions; (3) PacifiCorp incorrectly "rounds up" day-ahead balancing needs causing a systemic over-statement of market transactions; (4) PacifiCorp models the costs associated with an "extreme" level of wind penetration (reached in 2021), and incorrectly uses it to justify the wind integration cost ascribed throughout the study horizon; (5) the forecast relied upon in the PacifiCorp analysis, one to two hours prior to the beginning of each operating hour, leads to a significant overestimate of the hour-ahead forecast error; and (6) the wind integration analysis has significant ratemaking implications on the Company's power cost filing.

With NWEC's support, RNP and CUB recommended that a new study involving a public stakeholder process be completed within three months following the date of acknowledgement of the 2008 IRP. Until a new study is completed, RNP and CUB recommended that the Commission require the Company to use its previous wind integration cost of $5.10/MWh. PacifiCorp agreed that an updated study is appropriate, and committed to work with parties to complete a new study by the end of 2010.

Staff and the parties also expressed concerns with the Company's level of conservation resources for its entire service area, and the level of demand side management resources acquired in Oregon, as set forth in the preferred portfolio. Staff recommended that the Company assess its serve area-wide study against the Northwest Power and Conservation Council's (Council) study in the 2008 IRP update and undertake a new system-wide potential study for its next planning period. On November 3, 2009, PacifiCorp provided a preliminary comparison of its conservation study versus the Council's in its Response to Oregon Party Comments. PacifiCorp stated that the Company will continue to evaluate the Council's methodology and will incorporate these findings in an updated study to be completed in 2010.

RNP, CUB, and NWEC all expressed concerns about PacifiCorp's modeling of the impacts of greenhouse gas emission regulations and recommended improvements. RNP and CUB state that PacifiCorp focuses too much on carbon "intensity," rather than on actual carbon emissions. These parties stated that "since future carbon regulations of greenhouse will likely require reductions in emissions, rather than reductions in intensity levels, it would be helpful to see a similar chart which shows how the preferred portfolio will perform with regard to total emissions on a year-to-year basis."[5] Additionally, the parties asserted that including the impact of coal plant closures in PacifiCorp's IRP analysis is important to evaluate a least-cost approach to meeting carbon emission reduction targets.

RNP, CUB, and NWEC indicated that carbon dioxide emission levels should be included as specific and important risk factors. These parties stated that the existing methodology penalizes a portfolio with low emissions and does not adequately value least cost portfolios that actually reduce carbon emissions. NWEC also states that PacifiCorp's scoring system places inappropriate emphasis on insignificant cost differences among portfolios, and instead should place greater emphasis on the actual carbon emission differences between the portfolios. RNP and CUB support Staff's recommendation that the Company develop a more comprehensive evaluation of a hard-cap emissions standard and emission reduction plan, which includes the evaluation of coal plant closures. The Company agreed with parties that CO_2 emissions should be considered as a measure for scoring portfolio performance. PacifiCorp also agreed that enhanced modeling will allow it to better incorporate and analyze hard-cap emission standards. PacifiCorp will incorporate such modeling in its next IRP.

RNP, CUB, and NWEC expressed concern that PacifiCorp's "out-year resource selection" (resources selected after year 10) unduly influence near-term resource decisions. NWEC recommended that PacifiCorp modify its test portfolios so that all resource decisions beyond the 8 to 10 year horizon would be replaced with a standard resource.

In its Opening Comments, NWEC also recommended that the Company value flexibility and look at incorporating a dynamic modeling methodology similar to that used by the Council's study. NWEC suggests that development of portfolios in a world of

[5] *See* Opening Comments of RNP and CUB, page 7.

uncertainty using known futures does not appropriately reflect real world decision-making. NWEC believes that incorporating dynamic modeling will result in actions that "increase flexibility, or that have economic benefits regardless of future conditions (such as aggressive conservation), and that turn out to be more valuable than large capital-intensive and long-lead-time resources that reduce a utility's flexibility."[6]

PacifiCorp disagrees with NWEC's assertions. PacifiCorp states that valuing optionality and assigning a scoring weight would violate the Commission's requirement to treat resources on a consistent and comparable basis. The Company also believes that NWEC's suggestion that PacifiCorp replace all resource decisions beyond the 8-10 year horizon with a standard resource would also violate IRP rules requiring analysis of different resource options and the impacts of state and federal regulatory policies.

In its Reply Comments, NWEC recommended that the Commission not acknowledge PacifiCorp's 2008 IRP. NWEC argues that: (1) PacifiCorp's scoring system artificially amplifies insignificant differences in costs, and that the Company then relies upon those meaningless differences to choose a preferred portfolio; (2) the scoring system improperly combines cost and risk measures; (3) it provides additional scoring weight for increases in emissions; and (4) when faced with two portfolios that have insignificant cost differences, the Commission should acknowledge the portfolio which will result in lower emissions. NWEC recommends that PacifiCorp be required to work with parties to develop scoring criteria that do not depend upon small differences in rates and to include the statistical analysis to justify its scoring metrics.

Staff's Final Recommendations

At the February 2, 2010, public meeting, Staff recommended the Commission acknowledge PacifiCorp's 2008 IRP with nine agreed-upon modifications to the Action Plan and one exception. The exception is the wind integration analysis used in the 2008 IRP, cited above. The agreed-upon modifications consist of three revised Action Items and six additional Action Items, as follows:

Revised Action Items[7]

1. Action Item 3 (Peaking/Intermediate/Base-load Supply-side Resources) - In recognition of the unsettled U.S. economy, expected volatility in natural gas markets, and regulatory uncertainty, continue to seek cost-effective resource deferral and acquisition opportunities in line with near-term updates to load/price forecasts, market conditions, transmission plans and regulatory developments. PacifiCorp will reexamine the timing and type of gas resources and other resource changes as part of a comprehensive assumptions update and portfolio analysis to be conducted for the next business plan and 2008 IRP update.

[6] *See* NWEC Opening Comments, Page 3.
[7] Changes to the filed Action Plan shown in mark-up.

2. Action Item 9 (Planning Process Improvements) – For the next IRP planning cycle complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level. Use the enhanced model to provide more detailed analysis of potential hard-cap regulation of carbon dioxide emissions and achievement of state or federal emissions reduction goals. Also use the capacity expansion model to evaluate the cost-effectiveness of coal facility retirement as a potential response to future regulation of carbon dioxide emissions.

3. Action Item 9 (Planning Process Improvements) - In the next IRP planning cycle provide an evaluation of, and continue to investigate, ~~the formulation of satisfactory proxy~~ intermediate-term market purchase resources for purposes of portfolio modeling. ~~and contingent on acquiring suitable market data.~~

Additional Action Items

4. For future IRP planning cycles, include on-going financial analysis with regard to transmission, which includes a comparison with alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects, the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments and base case segments.

5. By August 2, 2010, complete a wind integration study that has been vetted by stakeholders through a public participation process.

6. During the next planning cycle, work with parties to investigate carbon dioxide emission levels as a measure for portfolio performance scoring.

7. In the next IRP, provide information on total CO_2 emissions on a year-to-year basis for all portfolios, and specifically, how they compare with the preferred portfolio.

8. For the next IRP planning cycle, PacifiCorp will work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.

9. In the next IRP planning cycle, PacifiCorp will incorporate its assessment of distribution efficiency potential resources for planning purposes.

DISCUSSION

I. Adherence of the Plan to Integrated Resource Planning Guidelines

In considering whether to acknowledge a resource plan, this Commission reviews the plan for adherence to our Guidelines for resource planning. We address each of the Guidelines separately, followed by the party's comments and our disposition.

Guideline 1: Substantive Requirements

Guideline 1a: *All resources must be evaluated on a consistent and comparable basis.*

In PacifiCorp's 2007 IRP, Staff and RNP cited concerns that the Company did not go far enough in modeling different types of renewable resources and new technologies such as carbon capture and sequestration (CCS) and integrated gasification combined-cycle coal plants (IGCC). Based on a Staff and RNP recommendation, PacifiCorp expanded the supply-side resource options considered in the Company's 2008 IRP.

Compliance with Guideline 1a by resource category:

Demand-Side Management. Staff cited several concerns with the Company's evaluation of conservation and demand response resources. Specifically, PacifiCorp did not conduct a system-wide study to determine the potential savings, the cost-effectiveness, and the customer impacts of implementing distribution system efficiency measures (i.e., conservation voltage reduction). PacifiCorp did not include this potential resource in its current DSM acquisition goal. The Company countered that it has did not develop an implementation plan for distribution efficiency because the IRP is not the proper forum for the development of such a plan.[8]

Renewable Resources. The Company modeled wind, geothermal, biomass and solar. Staff, RNP, CUB, and NWEC took issue with PacifiCorp's wind integration analysis. Specifically, RNP and CUB argued that PacifiCorp overstated its reserve requirements for wind by assuming that existing and new wind resources are 100 percent correlated, and by assuming that all day-ahead energy imbalances are settled through market transactions. PacifiCorp agreed that its wind integration study could be improved but is concerned that this represents a major undertaking for the Company. PacifiCorp not only cited parties' stated concerns, but also took into consideration the impact of transmission constraints and wind ramping events on wind integration costs.

Although Staff found that Action Item 1 of the IRP adequately incorporates sufficient acquisition targets of wind resources,[9] RNP and CUB argued that the existing wind

[8] *See* discussion under Guideline 6.

[9] PacifiCorp states that it will acquire an incremental 1,400 MW of renewable by 2018, for a projected renewable resource inventory of 2,540 MW.

integration study in the IRP may under estimate the most cost-effective amount of wind that should be incorporated in the Company's outer-year selection of resources in the portfolio.

Staff recommends conditioning the Action Plan to require PacifiCorp to complete a new wind integration study to be thoroughly vetted by stakeholders by August 2, 2010. RNP, CUB, and NWEC recommended that the Company be required to complete a new study earlier - within three months of the close of the docket. Staff counters, that without knowing the timing of the acknowledgement Order, and with PacifiCorp agreeing to complete the new study with a public participation process by August 2, Staff believes that its proposal will accomplish the goal of all parties.

Market Purchases. In Action Item 2, the Company included up to 1,400 MW of front office transactions per year through 2013, based on favorable market conditions. As discussed in Staff's Opening Comments, PacifiCorp's inputs into its IRP are out of date compared to what has actually occurred with regard to load, wholesale power prices and natural gas prices. PacifiCorp's stated intent is not to treat the IRP as a rigid schedule, but to allow flexibility in its procurement of not only market purchases, but more importantly, in timing resource acquisitions.

PacifiCorp recently requested to resume its 2008 all-source RFP,[10] which the Commission approved at its November 23, 2009, public meeting. The Commission adopted Staff's recommendation that the Company provide justification and analysis for the timing, type and location of the resource need based on its most current evaluation of loads, market prices and regulatory activity. Staff asserted that this condition should show whether market purchases are a more cost-effective means of meeting intermediate loads, as opposed to the acquisition of a new generating resource. The timing of a new generating resource may be appropriately delayed consistent with a protracted recovery from the current recession.

Staff recommended that Action Item 9 be conditioned to require PacifiCorp to provide an evaluation of intermediate-term market purchase opportunities, taking into consideration the most current evaluation of loads, market prices and regulatory activity,.

Distributed Generation. The company included dispatchable standby generation, combined heat and power (CHP) plants and on-site solar as resources for the CEM to select. Action Item 8 of the IRP states that the Company will pursue acquisition of 100 MW of distributed generation resources by 2018.

Fossil-Fuel Resources. Due to the uncertainty of future carbon regulation, as well as large increases in the cost of large coal-fired boilers (e.g., a cost increase of approximately 50 percent – 60 percent since the 2007 IRP) the Company will not select coal as a resource before 2020.

PacifiCorp evaluated CCS and IGCC technologies for selection in the model at an existing coal plant. The Company opined that CCS is not a viable option before 2025 "due to risk issues associated with technological maturity and underground sequestration

[10] *See* Docket UM 1360, PacifiCorp's request to resume the 2008 RFP, filed November 2, 2009.

liability."[11] Although IGCC plants have been built and operation demonstrated around the world, PacifiCorp argues that these facilities have been demonstration projects only, and their costs are significantly greater than conventional coal plants. PacifiCorp is a member of the Gasification User's Association. Over the last two years, the Company held a series of IGCC working group public meetings to "help provide a broader level of understanding for this technology."[12]

PacifiCorp's Action Plan includes 170 MW of emission free, coal plant capacity gains. The Company will undertake "dense pack" coal plant turbine upgrades at existing plants. Such cost-effective upgrades do not increase fuel consumption, heat input, or emissions.

PacifiCorp considered both SCCT and CCCT gas plant capacity additions. Both resources were chosen by the model and included in the preferred portfolio.

Action Item 3 shows a SCCT being added in 2016. However, when the Company did an analysis using its February 2009 load forecast, the CEM did not select the SCCT. PacifiCorp argued that since the February 2009 load forecast had little impact on resource development until 2016, the Company decided to retain the resource in the preferred portfolio.

In its Opening and Final Comments, Staff cited several concerns with the timing and acquisition of the CCCT and SCCT. Specifically, Staff is concerned that current economic conditions and a decline in load will have a significant impact on the decision to acquire these resources. PacifiCorp responded to Staff's concerns, stating that the IRP sets forth a "flexible acquisition strategy," rather than identifying specific resources on specific dates. Staff agreed with the Company that the resource actions identified in the IRP act as a guide for resource procurement and should not be held to a rigid interpretation. Staff recommended a modification to the language in Action Item 3 of the IRP that PacifiCorp agreed to that better reflects this flexibility.

Transmission. PacifiCorp stated it is moving forward with an expansion plan to eventually construct transmission lines and substations that are required to provide 1,500 MW over the proposed Gateway West lines and 1,500 MW over the proposed Gateway South lines. The transmission system model topology map on page 138 of the IRP showed all segments that were included in the System Optimizer model used to derive optimal resource expansion plans for all portfolios. This issue will be addressed in more detail under Guideline 5.

Guideline 1b: *Risk and uncertainty must be considered.*

The Company's stochastic modeling addressed the following sources of risk and uncertainty, including load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices and emission prices. To address the cost to comply with future

[11] *Id.*
[12] *See* IRP page 114.

regulation of greenhouse gas emissions, the Company conducted scenario analyses using $0, $45, $70, and $100 (in 2008 dollars) for CO_2 tax, as modeled for both cap-and-trade and tax strategies. PacifiCorp also analyzed compliance with Oregon State's emissions performance standards. The Company also performed sensitivity studies with various combinations of low, medium and high levels of the following factors: load growth, natural gas and electricity prices, CO_2 compliance costs, renewable portfolio standards, renewable energy tax credit expiration dates, high plant construction costs, capacity planning reserve margin, and achievable market potential for demand response programs.

Capital costs of generating resources, the level of achievable DSM potential, expiration of federal tax credits for renewable energy resources, capacity planning reserve margins and renewable portfolio standards are additional sources of risk and uncertainty identified in the plan.

Guideline 1c: *The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.*

In selecting its preferred portfolio, the Company considered both expected costs and associated risks and uncertainties. Additionally, the Company took into consideration the impact of its recent decision to defer the acquisition of a gas resource in 2012, and performed additional portfolio studies reflecting the removal of it as a planned resource in 2012.

PacifiCorp used a 20-year study period for portfolio modeling, and a real, levelized revenue requirement methodology for treatment of end-effects that are consistent with past IRP practice. The Company used standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail PVRR (mean of highest five Monte Carlo iterations) and the 95th percentile stochastic PVRR.

In its discussion of the preferred portfolio, the Company states it will be positioned to exceed current jurisdictional RPS requirements, and would potentially meet a 15 percent federal RPS requirement, such as the one contained in draft legislation proposed by U.S. Representatives Waxman and Markey.

In comments, NWEC, RNP, and CUB raised concerns about PacifiCorp's modeling of the last 10 years of the 20 year planning period. Specifically, NWEC opined that the Company's approach in the last ten years is not illustrative of real-world decision making, which would react to the constantly changing market conditions. NWEC argues that flexibility and optionality should be tested and valued in the Company's portfolio modeling approach. NWEC proposed that the Company should adopt the Council's dynamic modeling approach or alternatively "fix" a resource in all portfolios for the latter half of the planning period.

NWEC suggested that PacifiCorp value "flexibility" in its modeling. NWEC stated that "in a world of uncertainty developing portfolios using known futures does not appropriately reflect real world decision making." NWEC asserts that incorporating dynamic modeling will result in actions that "increase flexibility, or have economic benefits regardless of future conditions (such as aggressive conservation), and turn out to be more valuable than large capital-intensive and long-lead-time resources that reduce a utility's flexibility."[13] Specifically, NWEC recommended that PacifiCorp modify its test portfolios so that all resource decisions beyond the 8-10 year horizon would be replaced with a standard resource.

PacifiCorp disagreed with the NWEC assertions and stated that to value optionality and assess a scoring weight would violate the Commission's requirement to treat resources on a consistent and comparable basis. Similarly, the Company argued that NWEC's suggestion—i.e., that PacifiCorp replace all resource decisions beyond the 8-10 year horizon with a standard resource—would violate IRP rules requiring analysis of different resource options and the impacts of state and federal regulatory policies.

RNP and CUB also raised concerns associated with the Company's approach to resource acquisition in the last ten years of the planning period. These parties comment that it is "appropriate to allow the system optimizer model to select the near term part of the portfolio and then fix those decisions, but allow for different choices in later years as necessary."[14] They are concerned that PacifiCorp is effectively freezing its decision making at the present time, and not allowing for the fact that it is likely the future will be different. RNP and CUB argued that these later year resource decisions may be unduly weighting the selection process in earlier years by unduly weighting a portfolio's performance.

RNP and CUB recommended that PacifiCorp conduct capacity expansion optimizations in two passes. PacifiCorp should initially produce simulations to determine near-term resources to link to the IRP action plan. Subsequently, the Company should then produce simulations with the near-term resources fixed and allow the System Optimizer to optimize resources in the out-years. PacifiCorp agreed that investigation of alternative approaches for out-year resource acquisition is desirable. However, the Company is concerned that such a modeling approach may involve a trade-off with respect to the number of alternative futures that can be accommodated.

Staff agreed with RNP, CUB, and PacifiCorp, recommending that the following agreed-upon Action Item be added to PacifiCorp's IRP: PacifiCorp will work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.

Guideline 1c states that the goal of planning must be the selection of a portfolio of resources with the best combination of expected costs and risk for the utility and

[13] *See* NWEC Opening Comments, Page 3.
[14] *See* Opening Comments of RNP and CUB, at 8.

its customers. NWEC claimed that PacifiCorp's preferred portfolio does not meet this goal. Specifically, NWEC asserted that PacifiCorp's scoring system artificially amplified insignificant differences in costs and then relied upon those meaningless differences to choose a preferred portfolio. NWEC stated that the trade-off between cost and risk must be a subjective one, not a decision to be made in a scoring matrix. PacifiCorp countered that its performance scoring methodology necessarily involves a subjective determination of what measures are most important for judging the overall merit of resource portfolios.

In addition, NWEC believes PacifiCorp improperly combines cost and risk measures, and provides additional scoring weight for portfolios with higher emissions. NWEC urges the Commission to not acknowledge the 2008 IRP and to direct PacifiCorp to work with the parties to develop scoring criteria that do not depend upon very small differences in costs.

PacifiCorp strongly disagreed with NWEC's claim that the IRP's scoring system placed inappropriate emphasis on insignificant cost differences among portfolios.

Guideline 1d: *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

PacifiCorp argued that the increasing mix of renewable and other clean resources reflected in the 2008 IRP preferred portfolio reduced the carbon intensity of PacifiCorp's generation fleet, thereby positioning the Company well for meeting future climate change and renewable resource requirements. Staff found the Company's explanation of how the 2008 IRP meets Oregon's RPS requirements to be reasonable. Staff concluded that as proposed, the preferred portfolio exceeded current jurisdictional RPS requirements and would potentially meet a 15 percent federal RPS requirement currently proposed in "[t]he American Clean Energy and Security Act of 2009" authored by U.S. Senators Waxman and Markey that recently passed through the U.S. House of Representatives.

Commission Disposition

We conclude that PacifiCorp's 2008 IRP meets the substantive requirements in Order No. 07-002 with a modification to Action Item 3 and an exception. We describe the exception as follows:

RNP, CUB, Staff, and NWEC pointed out significant flaws in PacifiCorp's wind integration study in its 2008 IRP. Citing its own concerns, PacifiCorp took the position that these issues should be addressed in the context of a new study. The timing of the proposed wind integration study received comment by all parties. We conclude that PacifiCorp's commitment to complete a new study by August 2, 2010, as proposed by Staff, is a reasonable course of action. Therefore, we do not acknowledge the wind integration study in PacifiCorp's 2008 IRP. Rather, we adopt Staff's agreed-upon additional Action Item 5, above.

RNP and CUB urged the Commission to direct the Company to rely on the 2007 IRP wind integration analysis results for its Transition Adjustment Mechanism (TAM) filing until the Company completes a new wind integration study. However, RNP and CUB also correctly observe that the Commission does not make ratemaking decisions in an IRP proceeding. Therefore, we do not adopt the recommendation made by RNP and CUB that the Company rely on its 2007 IRP wind integration analysis for the purpose of its TAM filings. Rather, we find that this is a matter to be addressed in PacifiCorp's TAM filings.

The Commission supports Staff's agreed-upon modifications to Action Items 1 and 3, as described above, as well as the agreed-upon additional Action Item 8, above. At the February 2, 2010, public meeting, the Commission set forth an additional modification to Action Item 3: PacifiCorp will reexamine the Company's proposed gas resource action items, looking at both timing and need, using the most recent projections of loads, wholesale prices, regulatory activity, and other salient inputs as part of its 2008 RFP short-list submittal to the Commission (Docket UM 1360).

We believe these changes adequately address issues raised by the parties about optionality and the influence of out-year resource selection on near-term actions. We commend parties on their diligence and review of the complex and complicated issues related to modeling and risk analysis in the IRP. We support the continued investigation of new methodologies, appropriate risk analysis, and scoring criteria that all parties have conducted in this process.

NWEC asserted that PacifiCorp makes its trade-off decision between cost and risk in the preferred portfolio based purely on the statistical outcome of the scoring matrix from PacifiCorp's risk analysis. NWEC indicated that the Company's decision should instead be subjective. PacifiCorp refuted this claim, commenting that its performance scoring methodology involves subjective decision making throughout the process on what measures are most important for judging the overall merit of the portfolio. We find that both parties' arguments have merit, and we clarify that the Commission recognizes the need for subjective judgment when reviewing the modeling and risk analysis results. In both the investigation of IRP Guidelines (UM 1056) and Competitive Bidding Guidelines (UM 1182), we stated that results are not intended to be followed lockstep without benefit of sound judgment. However, in recognition of this, it is equally important for the utility (and others) to explain that judgment as clearly as possible.

We do not agree with NWEC's recommendation that the Commission not acknowledge PacifiCorp's 2008 IRP based on scoring criteria concerns and other statistical issues.

For purposes of clarity, in future IRP filings the Commission requires the Company to label its IRP filings with the year in which the filing is made.

Guidelines 2 and 3: Procedural Requirements

Guidelines 2 and 3 lay out procedural requirements and specify procedures for filing and review of resource plans. Energy utilities must file an integrated resource plan within two years of the previous acknowledgement order. PacifiCorp filed this plan on May 29, 2009, approximately 13 months after the Commission entered its acknowledgement order on the Company's 2007 IRP.[15] PacifiCorp's filing was timely under Order No. 07-002.

The Commission and the public must be involved in the utility's planning process. PacifiCorp provided extensive opportunities for public input, and submitted a draft of its plan for comment by participants on April 8, 2009.

The Commission held a Public Meeting regarding PacifiCorp's plan on September 8, 2009. On October 8, 2009, RNP, CUB, NWEC, and Staff submitted written comments to the Commission regarding the plan. PacifiCorp filed a reply on November 3, 2009. Staff filed its Final Comments on December 8, 2009. PacifiCorp, RNP, CUB, and NWEC filed additional comments on January 7, 2010, responding to Staff's comments and recommendations.

In its Reply Comments to Staff, filed on January 7, 2010, PacifiCorp stated its intent to file a 2008 IRP update on March 31, 2010. The Company states this date will keep the "IRP filing cycle consistent across all state jurisdictions, recognizing that PacifiCorp has already received acknowledgment orders from a number of commissions."

Commission Disposition

We conclude PacifiCorp's 2008 IRP meets the Commission's procedural requirements with the exception of its intent to file the 2008 IRP update on March 31, 2010, regardless of the date of issuance of this acknowledgement Order.

PacifiCorp's stated intent to file its 2008 IRP update is not in compliance with Guideline 3f: *Each utility must submit an annual update on its most recently acknowledged plan*. An update on March 31, 2010, made shortly after this order is entered, is too soon to meet the provisions of Guideline 3f and 3g. Updating an IRP is intended to provide the Commission with an assessment of what has changed since the *acknowledgement* order, not simply to update what has changed since the plan was filed. PacifiCorp stated that it would like to achieve "consistency" among all state jurisdictions; however, Oregon's guidelines are clear on this issue and seem to contradict PacifiCorp's intent of aligning the state commission requirements.

Additionally, PacifiCorp's desire to align the IRP process across all of its state jurisdictions should not disproportionately impact the IRP process in Oregon. PacifiCorp chose to file its 2008 IRP in its other state jurisdictions prior to making its filing in Oregon. The combination of the late filing date in Oregon and the IRP update date set to meet timelines in other jurisdictions disadvantages the Oregon IRP process in two ways. First,

[15] The Commission entered Order No. 08-232 in docket LC 42 on April 24, 2008.

many of the input assumptions and variables used in the modeling are out of date at the time of IRP acknowledgment in Oregon. Second, although the IRP update is designed, in part, to address out of date assumptions and variables, the proposed alignment of the 2008 IRP Update across all jurisdictions is too early for the Oregon IRP process. This proposed alignment of the company's IRP filings results in a lack of timely and relevant information in Oregon.

In resolution, we direct the Company to file a 2008 IRP Update approximately one year after the date of this Order.[16] In addition, we direct parties to discuss and attempt to resolve these timing issues prior to PacifiCorp's next IRP filing. The Commission is confident that parties can satisfy both the Company's desire to coordinate its state jurisdictional requirements and our desire to have a more timely review process in PacifiCorp's next IRP.

Guideline 4: Plan Components

Guideline 4 identifies fourteen separate elements that an IRP must include to meet the Commission's IRP guidelines.

The Company included low, medium, and high load growth forecasts for scenario analyses in its System Optimizer model for portfolio development. Stochastic variability of loads was also captured in its risk analyses. The company included loads among its stochastic risk parameters in testing all its Risk Analysis portfolios.

PacifiCorp made six major changes to its sales and load forecasting method. First, PacifiCorp used load research data to model the impact of weather on monthly retail sales and peaks by state by class. Second, the time period used to define normal weather was updated from the previous period of 1971-2000 to a 20-year time period of 1988-2007. This time period change better captured the trend of increasing temperatures observed in both summer and winter. Third, the historical data period used to develop the monthly retail sales forecasts was updated to cover 1997-2007. Fourth, monthly peaks were forecasted for each state using a peak model with historical data from 1990-2007. This model allows the Company to better predict monthly and seasonal peaks. Fifth, system line losses were updated to reflect actual losses for the five years ending December 31, 2007, as opposed to the previous IRP which was based on calendar-year 2001 data. Finally, PacifiCorp performed analysis and made adjustments to reflect current economic conditions by mirroring the load changes experienced in the previous recession (2001-2002).

PacifiCorp relied on a November 2008 load forecast for the development of the load and resource balance and portfolio evaluations. The Company also performed a sensitivity analysis on the preferred portfolio using a February 2009 load forecast, which better took into consideration the current economic climate. Staff cited concerns with the use of the November 2008 load forecast in the development of the preferred portfolio. In its

[16] The Company may choose to file its intended March 31, 2010 IRP Update in Oregon. However, as stated above, we do not believe this filing meets the intent of Guideline 3f and 3g and require the Company to file a subsequent update approximately one year after the date of this Order.

Opening Comments, Staff stated that on an actual basis, the rate of growth in loads has seen significant declines year over year and does not support PacifiCorp's expectation of a rebound recovery from this recession, but instead Staff believes that a more protracted recovery may occur.

PacifiCorp states it was not able to completely refresh its 2008 IRP using the February 2009 forecast because it would have been impossible to meet its IRP filing deadlines. PacifiCorp did provide a sensitivity analysis of the load change on the preferred portfolio, inclusive of break-even points with regard to acquisition of the CCCT and the level of peak load change that would be required to defer the acquisition of the resource to later years. In its Final Comments, Staff agreed that re-doing the IRP portfolio analysis, taking into consideration large load and market price changes, would have been a major undertaking. Staff believes the additional analysis provided by PacifiCorp - coupled with the ongoing analyses to be conducted as part of its 2008 RFP, business plan, and IRP update - sufficiently justifies its preferred portfolio in the 2008 IRP.

Energy Needs. PacifiCorp projects energy consumption to grow system-wide at an average annual rate of 2.1 percent from 2009 through 2018. This rate is lower than the 10-year average rate of 2.4 percent in the Company's 2007 IRP. For the second half of the study period, the Company projects a 1.2 percent system-wide growth rate, and for the 20 year period an overall 1.6 percent growth rate. PacifiCorp projects that its system will become short on energy by 2012.

The Company's February 2009 forecast also shows a 2.1 percent growth rate for the period of 2009-2018, with the second half of the study period at 1.1 percent and an overall 20 year period growth rate of 1.6 percent.

Capacity Needs. In the November 2008 forecast, PacifiCorp forecasts coincident peak loads to grow by 2.4 percent system-wide from 2009-2018.[17] For comparison, the 2007 IRP forecasted coincident peak load to grow by 2.6 percent for the period of 2007-2016. By control area, the Company expects peak loads to grow by 2.7 percent in the east and 1.6 percent in the west. Total peak load growth is forecast to be 238 MW annually, with Oregon expected to contribute only 37 MW. The February 2009 forecast shows coincident peak loads to grow by 2.2 percent system-wide from 2009-2018 with load growth of 217 MW annually. PacifiCorp forecasts that it will become short on capacity in 2011.

As compared to previous IRPs, the Company projects both energy and capacity to grow, but at a lower rate than the historical average. Current economic conditions have had a significant effect on PacifiCorp's loads. However, a comparison of the November 2008 load forecast to the February 2009 load forecast shows that projected peak loads for the east side of the system actually increased relative to the November 2008 forecast. In its Final Comments, Staff remained skeptical that the Company's November 2008 or February 2009 forecast fully captured the current economic climate. The Company has reiterated its statement in the 2008 IRP that it will do a more thorough analysis of the

[17] Coincident peak load occurs in summer driven by air conditioning.

implications of a declining load and market price forecast on any resource acquisitions, in its 2008 IRP update.

Transmission. The Company modeled existing transmission rights and future transmission additions associated with the portfolios tested. In addition, the Company included three transmission resource options in System Optimizer; however, none of these options was selected.

With regard to Guideline 4l, the selection of a portfolio that represents the best combination of cost and risk for the utility and its customers, the Company considers both stochastic and scenario risks in its decision on the preferred portfolio. Stochastic risk applies when probability distribution functions can be estimated. Such is the case with fuel and electricity market prices, hydro conditions, loads and thermal availability. Scenario risks represent abrupt changes in risk factors, such as sudden changes in natural gas prices, regulatory compliance costs and capital costs.

PacifiCorp conducted stochastic analyses to arrive at both its cost and risk determinations. For the 20-year study period, one hundred stochastic runs are conducted for each of four modeled levels of CO_2 adders, ranging from zero to $100 per ton (levelized, in 2008 dollars). PacifiCorp assumes a 2013 implementation date. The Company calculates present value of revenue requirement (PVRR) assuming a direct tax adder and a cap-and-trade compliance strategy with trading values that are equivalent to the tax adders. Stochastic Mean PVRR, the average of 100 modeled PVRR outcomes, is the Company's primary cost metric.

Risk-adjusted Mean PVRR. The risk-adjusted PVRR is calculated as the stochastic mean PVRR plus the expected value of the 95th percentile PVRR. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected PVRR based on the 100 Monte Carlo simulations conducted for each production cost run. Other risk measures displayed in the IRP are the Upper-Tail PVRR, the 95th Percentile and 5th percentile PVRR, and the Production Cost Standard Deviation.

Guideline 4m requires the identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.

The Company included sensitivity case 40 to meet the Commission's requirement from the 2007 IRP, which stated that it should "develop a plan to meet the CO_2 emissions reduction goals in Oregon HB 3543."[18] Staff and intervening parties commented that they did not believe the Company went far enough with the inclusion of only one sensitivity case, and that it should go further in modeling a cap-and-trade mechanism with a declining number of carbon allowances and hard-cap emission standards. PacifiCorp agreed to include this additional analysis in future IRPs and summarizes recent changes to its model which will facilitate this.

[18] *See* Docket LC 42, Order No. 08-232 at 36.

Commission Disposition

PacifiCorp's plan provides the required elements under Guideline 4.

Related to Guideline 4c, we share Staff's skepticism of the Company's projected load growth rates, as well as PacifiCorp's expectation of a rebound recovery from this recession. Staff's proposed revision to Action Item 3 - as further modified by this Commission - will provide updated information and better insight into to the Company's near-term resource needs.

Related to Guideline 4m, we agree with Staff and intervening parties that modeling reductions in carbon emissions is important in light of potentially stringent carbon regulations in the near-term. Additionally, we believe it is necessary that PacifiCorp's modeling include the impact of early retirement of existing coal plants as a very real possibility. Therefore, we adopt Staff's agreed-upon Action Plan modification 2, above.

Guideline 5: Transmission

PacifiCorp requested the Commission acknowledge two important, short-term transmission actions: 1) obtaining a Certificate of Public Convenience and Necessity for segments of Gateway Central and Gateway West; and 2) construction of Path C Upgrades that include the Populus-Terminal and the Mona-Oquirrh segments. In its IRP, the Company described the Company's general transmission expansion plans[19] and the individual segments of the Gateway transmission project. In Opening Comments, Staff pointed out that the Company did not provide a cost/benefit analysis of the proposed transmission lines, or a comparative analysis to other resource types, showing that the proposals for acknowledgement were in the best interest of PacifiCorp's customers.

PacifiCorp noted that the Energy Gateway development is a *transmission strategy* developed to be flexible and scalable as conditions change over time. The overall strategy is financially assessed each year, and each segment is reviewed and justified on an individual basis. The Company considered multiple inputs in the decision-making process including compliance and reliability, net power cost analysis, and a least-cost analysis of alternatives.

In its Final Comments, Staff discussed PacifiCorp's additional analysis of the on-going Energy Gateway financial analysis and the supporting work papers. Specifically, Staff noted that for the Path C Upgrades - including Populus-Terminal and Mona-Oquirrh - the Company performed portfolio evaluation with, and without, the 300 MW Path C upgrade using the IRP stochastic production cost model. Portfolios with the Path C upgrade out-performed portfolios without the upgrade based on stochastic cost, risk, and supply reliability measures. Therefore, after reviewing the analysis, Staff concluded that the proposed transmission segments provided increased reliability, additional transfer capability, and also

[19] *See* IRP Chapters 4 and 10.

supported integration with larger segments. Staff concurred that there is an overall benefit to Oregon customers that outweighs the proposed capital investment.

With regard to Guideline 5 and the requirement that the Company treat the transmission facility as a resource option, Staff found that the Company met this guideline. In response to Staff Data Request No. 32, the Company discussed its analysis of the Gateway transmission project with, and without, development of Wyoming resources. Using the preferred portfolio as the base case assumption, the analysis showed that the preferred portfolio was more cost effective with the inclusion of the transmission projects, as opposed to incremental development of Wyoming resources. Staff recommended that for future IRPs the Company provide its on-going transmission analysis as part of its IRP.

Commission Disposition

We conclude that the integrated resource plan complies with Guideline 5. In addition, we adopt Staff's agreed-upon additional Action Item 4, as set forth above.

Guideline 6: Conservation

Guideline 6 requires utilities to ensure that a conservation potential study is conducted periodically for service territories. Guideline 6 also requires PacifiCorp to determine the amount of conservation resources in its best cost/risk portfolio and to specify annual savings targets in the Company's Action Plan.

Under the Commission's updated planning guidelines, a utility should analyze potential conservation resources regardless of limits on funding. PacifiCorp's 2008 IRP included data provided from a system-wide DSM potential study that was completed in June of 2007. The Company converted the DSM-potential estimates into conservation supply curves. This study provided a broad estimate of the size, type, location, and cost of demand-side resources.

Staff and certain intervening parties questioned whether the IRP understated the cost-effective potential in PacifiCorp's Oregon service territory, as based on a comparison with the Council's conservation potential study for the Northwest.

In its Response to the Oregon Party Comments filed on November 3, 2009, PacifiCorp provided a preliminary assessment of the 2008 IRP estimates as compared to the Council's conservation potential estimates for the Northwest. The preliminary assessment described the high-level differences between these two sets of estimates. PacifiCorp commented that the primary differences relate to study timing differences, distribution energy efficiency, the cost-effectiveness methodology, and the cost-effectiveness threshold used. In its Response to Final Comments, PacifiCorp committed to continue its evaluation of the Council's methodology in more detail and to incorporate any necessary methodological changes in an updated DSM potential study to be completed in 2010, as required by Guideline 6a.

Staff specifically faulted PacifiCorp's 2008 IRP for not identifying savings from distribution efficiency measures (conservation voltage reduction measures). These conservation measures were highlighted in both the May 2006 and February 2009 conservation potential studies. Further, they have been identified as a major cost-effective resource in the Council's 6th Annual Plan. Therefore, Staff recommended the Company incorporate its assessment of distribution efficiency potential resources in the next planning cycle.

Commission Disposition

We share Staff and intervenor concerns with regard to PacifiCorp's modeling of cost-effective conservation resources in the Northwest. We support the agreed-upon additional Action Item 9 above and support PacifiCorp's ongoing analysis of the Council's potential study and conservation acquisition targets that can be directly applied in PacifiCorp's service areas. We support timely assessment of distribution system efficiency measures and the development of implementation plans to achieve those efficiencies.

Guideline 7: Demand Response

PacifiCorp categorized demand response into two types: Class 1 DSM, which includes dispatchable load control, scheduled irrigation and thermal energy storage; and Class 3 DSM, which includes curtailable rates, critical peak pricing and demand buyback.

In the 2004 IRP, the Company took its first step toward comparable treatment of demand response and supply-side resources by allowing the CEM to choose Class 1 DSM and displace supply-side resources in the preferred portfolio. In its 2007 IRP, the Company was required to model Class 1 and Class 3 DSM supply curves, as portfolio options that compete with supply-side options, and to analyze the cost and risk reduction benefits of acquiring DSM. The Company complied with this requirement. However, Class 3 DSM was not selected by the model in any of the portfolios. The model did select a small amount of Class 1 DSM capacity (2 to 7 MW) and a sizable amount of Class 2 DSM (1,537 MW to 2,183 MW).

With regard to Class 3 DSM, the Company explained that it requires more information on the extent to which these products could be sufficiently reliable to be classified as firm capacity resources. The Company will conduct such research for its next IRP (Action Item 7).

Staff took the position that the Company met Guideline 7; i.e., evaluating demand response resources on par with supply-side and demand-side resources. However, Staff commented that the Company needs to go further in evaluating the cost and amount of resources from curtailable rates, demand buybacks, and critical peak pricing programs.

In reply, PacifiCorp stated that it made the commitment in Action Item 7 to continue to evaluate Class 3 DSM programs as potential firm resources for long term planning, and will also update its Class 3 DSM resource characterization as part of a new DSM resource potential study to be conducted in 2010.

Commission Disposition

We share Staff's concerns about PacifiCorp's evaluation of the cost and amount of resources from curtailable rates, demand buybacks, and critical peak pricing programs. We support PacifiCorp's commitment to evaluate its Class 3 DSM resources and to produce a new DSM resource potential study, as identified in the 2008 IRP Action Item 7, as reasonable action steps.

Guideline 8: Environmental Costs

Guideline 8, as modified by Order No. 08-339, contains four requirements. Under this guideline, the Company must model base case and other compliance scenarios, test alternative portfolios against the compliance scenarios, conduct CO_2 trigger point analyses, and develop an Oregon compliance portfolio. The first requirement directs the Company to model what it considers to be the most likely regulatory compliance future for greenhouse gas emissions, as well as other possible credible scenarios. For the second requirement, the utility must estimate, under each of the compliance scenarios, the PVRR cost and risk measures, for both its preferred portfolio and a reasonable set of alternative portfolios. The third requirement directs the utility to identify the carbon dioxide emission cost adder level that triggers the selection of a portfolio that is substantially different from the preferred portfolio. The final requirement requires PacifiCorp to develop a portfolio to achieve voluntary carbon emission reduction targets set forth in Oregon law.

In its consideration of Guideline 8, PacifiCorp commented that no single CO_2 reduction compliance approach has emerged as a consistent front-runner for adoption; therefore, the Company considered a wide range of carbon cost outcomes. The Company modeled CO_2 tax for all core cases with an implementation date of 2013.

The Company's trigger analysis looked at the production cost impact of up to \$70/ton CO_2 tax. Changes in the preferred portfolio based on this analysis resulted in greater acquisition of DSM programs and high-efficiency distributed generation to help minimize the carbon footprint. The greatest changes however, opined PacifiCorp, would be the additional acquisition of 2,500 MW of wind and at least 70 MW of geothermal capacity or other base-load renewable resources with the timing and annual amounts tied to the start of the CO_2 regulations and a trajectory of the cost.

RNP, CUB, and NWEC all expressed concerns with PacifiCorp's modeling of greenhouse gas emissions and suggested improvements. RNP and CUB suggested that PacifiCorp focuses too much on carbon "intensity" rather than actual carbon emissions. RNP and CUB commented that since future carbon regulations will likely require reductions in emissions rather than reductions in intensity levels, it would be helpful to see a chart showing how the preferred portfolio will perform with regard to total emissions on a year-to-year basis. RNP, CUB, and NWEC asserted that the Company must include the impact of coal plant closures in its analysis to determine the least-cost approach to meet carbon reduction targets. Staff agreed with these parties and recommended that the Company should further evaluate emission reductions, showing total emissions for each portfolio, as well as that PacifiCorp should incorporate the effect of the closure of coal facilities in its next IRP plan.

PacifiCorp agreed with RNP and CUB that a graph showing carbon emissions for the preferred portfolio, and possibly for other portfolios, would be helpful for the reader of the IRP. In addition, the Company agreed to include the effect of the closure of coal facilities and will undertake additional analysis of hard-cap emission reduction portfolios for its next IRP.

RNP, CUB, and NWEC claimed that carbon dioxide emission levels should be included as specific, and indeed, important risk factors. The parties stated that the existing methodology penalizes a portfolio for its emission reductions and does not adequately address least-cost approaches to meet carbon emission targets. NWEC further stated that PacifiCorp's scoring system placed inappropriate emphasis on insignificant cost differences among portfolios, and instead, should place greater emphasis on the actual carbon emission differences between the portfolios.

The Company agreed with the parties that CO_2 emissions as a measure for portfolio performance scoring has merit and stated that enhanced modeling will allow it to better incorporate and analyze hard-cap emission standards. Consequently, the Company agreed to incorporate this in its next IRP planning cycle.

Commission Disposition

We conclude that PacifiCorp's IRP meets the current requirements under Guideline 8. We support Staff's agreed-upon additions to Action Items 6 and 7, as detailed above, to PacifiCorp's Action Plan. As stated under Guideline 4m, we also adopt Staff's modification to Action Item 9, as agreed to by PacifiCorp, to require the Company to provide a more detailed analysis of hard-cap emission standards and to incorporate the effect of the closure of coal facilities in its next IRP plan.

Guideline 9 and 10: Direct Access Loads and Multi-state Utilities

Guideline 9 requires an electric utility's load-resource balance to exclude customer loads that are effectively committed to service by an alternative service provider. Guideline 10 requires multi-state utilities, like PacifiCorp, to plan their generation and transmission systems on an integrated system basis that achieves a best cost/risk portfolio for their retail customers.

The Company does not offer a permanent opt-out program. Therefore, it plans for all Oregon loads, including those customers who have selected direct access or standard offer services. PacifiCorp plans on a system wide basis.

Staff found the IRP complies with these Guidelines.

Commission Disposition

We conclude that PacifiCorp's 2008 IRP complies with Guidelines 9 and 10.

Guideline 11: Reliability

Under Guideline 11, electric utilities should:

a. Analyze reliability within the risk modeling of the actual portfolios being considered;
b. Determine loss of load probability (LOLP), expected planning reserve margin, and expected and worst-case unserved energy by year; and
c. Demonstrate that the selected portfolio achieves the utility's stated reliability, risk and cost objectives.

PacifiCorp analyzed reliability, as part of the portfolio risk modeling, by evaluating a subset of the portfolios at both a 12 percent and a 15 percent planning reserve margin, and then evaluating loss of load probability and average and worst-case energy not served (ENS). Ultimately, the Company selected a portfolio with a 12 percent planning reserve margin, concluding that it is not cost-effective to invest in incremental generating capacity for reserves because the cost premium for such investment is above the assumed ENS cost.

Staff found that the selected portfolio achieves the Company's reliability, risk and cost objectives.

NWEC commented that it does not support the use of the LOLP and ENS metrics to score the portfolios themselves. Rather, NWEC asserts that for increased reliability, there should be a separate determination of how much to invest in additional reserves.

Commission Disposition

We conclude PacifiCorp's 2008 IRP meets Guideline 11. With regard to NWEC's suggestion that appropriate reserves be separately determined, we direct the parties to discuss this issue in the next planning cycle.

Guideline 12: Distributed Generation

PacifiCorp evaluated combined heat and power (CHP, or cogeneration) and dispatchable customer standby (diesel) generation resources. The Company's Action Item 8 includes 50 MW of CHP and 50 MW of cost-effective customer standby generation. Additionally, the Company stated that if the economic recession and market conditions continue to support elimination of simple-cycle gas units or other peaking resources, as indicated by the IRP portfolio modeling for the 2010 business plan, the Company will seek to acquire an additional 40 MW of customer standby generation.

Commission Disposition

We conclude PacifiCorp's 2008 IRP complies with Guideline 12. We continue to encourage the Company to pursue all types of distributed generation resources and account for all potential benefits.

Guideline 13: Resource Acquisition

Guideline 13 establishes requirements for acquiring resources in the utility's action plan. The company provided its acquisition strategy for its action plan and a brief assessment of the advantages and disadvantages of owning vs. purchasing resources. At the time of filing, the Company had suspended its 2008 RFP; under the now resumed 2008 all-source RFP, the Company has included a CCCT at the Lake Side site as its single benchmark resource.

Commission Disposition

We conclude that PacifiCorp's 2008 IRP meets Guideline 13.

JURISDICTION

PacifiCorp is a public utility in Oregon that provides electric service to the public as defined by ORS 757.005.

CONCLUSION

PacifiCorp is a public utility subject to the jurisdiction of the Commission.

PacifiCorp's 2008 IRP, as modified in this order, reasonably adheres to the principles of resource planning set forth in Order No. 07-002 and should be acknowledged with the following exception, and nine agreed-upon modifications:

Exception:

PacifiCorp's wind integration analysis in its 2008 IRP.

Modifications agreed to by PacifiCorp pursuant to Staff's recommendations:

Revised Action Items

1. Action Item 3 (Peaking/Intermediate/Base-load Supply-side Resources) - In recognition of the unsettled U.S. economy, expected volatility in natural gas markets, and regulatory uncertainty, continue to seek cost-effective resource deferral and acquisition opportunities in line with near-term updates to load/price forecasts, market conditions, transmission plans and regulatory developments. PacifiCorp will reexamine the timing and type of gas resources and other resource changes as part of a comprehensive assumptions update and portfolio analysis to be conducted for the 2008 RFP final short-list evaluation in the RFP, approved in Docket UM 1360, the next business plan and the 2008 IRP update.

2. Action Item 9 (Planning Process Improvements) - For the next IRP planning cycle complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level. Use the enhanced model to provide more detailed analysis of potential hard-cap regulation of carbon dioxide emissions and achievement of state or federal emissions reduction goals. Also use the capacity expansion model to evaluate the cost-effectiveness of coal facility retirement as a potential response to future regulation of carbon dioxide emissions.

3. Action Item 9 (Planning Process Improvements) - In the next IRP planning cycle provide an evaluation of, and continue to investigate, the formulation of satisfactory proxy intermediate-term market purchase resources for purposes of portfolio modeling and contingent on acquiring suitable market data.

Additional Action Items

4. For future IRP planning cycles, include on-going financial analysis with regard to transmission, which includes: a comparison with alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects, the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments and base case segments.

5. By August 2, 2010, complete a wind integration study that has been vetted by stakeholders through a public participation process.

6. During the next planning cycle, work with parties to investigate carbon dioxide emission levels as a measure for portfolio performance scoring.

7. In the next IRP, provide information on total CO_2 emissions on a year-to year basis for all portfolios, and specifically, how they compare with the preferred portfolio.

8. For the next IRP planning cycle, PacifiCorp will work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.

9. In the next IRP planning cycle, PacifiCorp will incorporate its assessment of distribution efficiency potential resources for planning purposes.

In addition, the Company will file its 2008 IRP Update approximately one year after the date of this Order, in compliance with Guideline 3.

Effect of the Plan on Future Rate-making Actions

Order No. 89-507 set forth the Commission's role in reviewing and acknowledging a utility's least-cost plan as follows:

> The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision- maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission***.
>
> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan. *See* Order No. 89-507 at 6 and 11.

The Commission affirmed these principles in Docket UM 1056.[20]

This order does not constitute a determination on the ratemaking treatment of any resource acquisitions or other expenditures undertaken pursuant to PacifiCorp's 2008 IRP. As a legal matter, the Commission must reserve judgment on all rate-making issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the rate-making process. In ratemaking proceedings in which the

[20] *See* Order No. 07-002 at 24.

reasonableness of resource acquisitions is reviewed, the Commission gives considerable weight to utility actions that are consistent with acknowledged integrated resource plans. Utilities are also expected to explain actions taken that may be inconsistent with Commission-acknowledged plans.

ORDER

IT IS ORDERED that the 2008 Integrated Resource Plan filed by PacifiCorp on May 29, 2009, is acknowledged in accordance with the terms of this order and Order No. 07-002, as it was corrected by Order No. 07-047.

Made, entered, and effective FEB 24 2010.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON