Response to the Utah Party Comments on PacifiCorp's 2011 Integrated Resource Plan

Docket 11-2035-01

1. INTRODUCTION

PacifiCorp filed its 2011 Integrated Resource Plan (IRP) with the Public Service Commission of Utah (Commission) on March 31, 2011, and an Addendum to the IRP filed on June 27, 2011. The Company's IRP was prepared in accordance with the Commission's IRP standards and guidelines in Docket No. 90-2035-01, demand-side management analysis and data reporting requirements from Orders for Docket Nos. 09-035-56, and 2008 IRP acknowledgment requirements from the Report and Order for Docket No. 09-2035-01. The Commission's criterion for IRP acknowledgment is that the plan is deemed reasonable at the time it is presented. As part of its review the Commission determines if the IRP adequately adheres to the IRP Standards and Guidelines established under Docket No. 90-2035-01, and takes into consideration the "merit and applicability" of public comments.[1]

As part of the IRP acknowledgment schedule adopted by the Commission for this proceeding, parties filed comments and acknowledgment recommendations by September 7, 2011. Six parties submitted written comments: Division of Public Utilities (DPU), Office of Consumer Services (OCS), Utah Association of Energy Users (UAE), Utah Clean Energy (UCE), Western Resource Advocates (WRA), and Sierra Club.

In response to these comments, PacifiCorp submits these reply comments for consideration. Following an executive summary/recommendations section, the Company addresses first the issues or concerns identified by more than one party. These common issues/concerns include the following:

- Evaluation of coal plant environmental control investments and early replacement options
- Wind resource modeling assumptions
- Treatment of geothermal resources
- Adequacy of Energy Gateway transmission scenario modeling and project justification
- The 2010 wind integration study
- Use of long-term load volatility parameters for stochastic production cost modeling
- Justification for a 13-percent capacity planning reserve margin (PRM)
- Adequacy of the IRP model tutorial session and model accessibility

The Company then replies to other specific comments provided by the parties. These replies are organized by responding party.

[1] Public Service Commission of Utah, *Report and Order on Standards and Guidelines* (Docket No. 90-2035-01), pp. 22-3.

2. EXECUTIVE SUMMARY AND RECOMMENDATIONS

A number of the parties raise concerns with respect to perceived shortcomings in modeling assumptions that bias the outcome of resource selection, particularly with respect to identification and analysis of environmental compliance costs and renewable resources. In these comments, the Company provides clarification to support its portfolio modeling assumptions and resource strategy conclusions. The Company also provides, as an attachment to these reply comments, a Supplemental Coal Replacement Study that addresses many of the parties' concerns regarding analysis of coal plant pollution control investments and associated regulatory compliance requirements.

The Company also points out that a number of the parties still mistakenly interpret the IRP preferred portfolio as a set of rigid resource commitments rather than a guide for action plan development. This is particularly true with respect to such issues as wind resource timing, geothermal resources, and the Energy Gateway transmission plan.

Finally, the Company disagrees with several parties that the IRP should not be acknowledged because Standards and Guidelines have allegedly not been met. Compliance with the Standards and Guidelines will always be a point of contention given room for interpretation and the differing agendas and motivations of the parties. We respectfully request that the Commission and the parties consider the IRP in the context of balancing customer interests across an extensive and capital-intensive portfolio of generation and transmission assets, and recognizing PacifiCorp's continued commitment to meet the Commission's IRP guidelines, acknowledgment order requirements, and IRP action item obligations.

With the responses and clarifications contained in this filing, along with the Coal Replacement Study submitted in conjunction with these comments, PacifiCorp believes that the requirements of the Commission's IRP Standards and Guidelines have been met, and that the Company's 2011 IRP should be acknowledged.

3. REPLY COMMENTS: COMMON ISSUES

Evaluation of coal plant environmental control investments and early retirement options

Five of the six parties—OCS, WRA, UCE, UAE, and Sierra Club—criticize the Company for not including a comprehensive assessment of coal unit investment costs and cost-effective coal plant replacement options in the IRP. The key themes and remarks from parties are as follows:

- OCS recommends that "the Commission order the Company to begin to incorporate a more refined analysis of coal-related issues in modeling coal plant displacement scenarios in future IRPs. At a minimum, the Company must reflect updated conditions regarding increasing costs associated with coal supply sources, availability and quality. Further, to develop portfolios and action plans that are in the public interest, no additional significant investment in [pollution control technologies (PCTs)] should be pursued without a more robust economic analysis of the long-term costs of replacement options."

- WRA states that "the coal retirement studies do not evaluate what they were intended to evaluate – earlier retirement as an alternative to ongoing investment. First, the modeling did not allow pollution control expenditures before 2017 to be avoided. As the discussion above makes clear, the majority of expenditures needed to meet the Regional Haze Rule will be sunk before 2017. Second, by assuming pollution control investments between 2012 and 2017 are sunk costs and by further assuming that the incremental fixed O&M and capital from these investments must be recovered before the unit can be retired, these pollution control investments could actually extend the lives of the plants in the study, a seemingly perverse result. Finally, PacifiCorp's treatment of coal fuel costs for this study contributed to this effect by lowering the modeled operating costs and increasing the modeled fixed O&M, both of which would lead to operating the plants longer."
- Sierra Club requests that the Commission require the Company to develop unit-by-unit Continued Use and Operation (CUO) studies in the IRP. Sierra Club states that the CUO studies should: (1) test the economic merit of continued use with environmental retrofits against the retirement and optimized portfolio replacement; (2) evaluate the risk of retirement under difference cost scenarios, and; (3) allow feasible replacements as of the first year of the IRP analysis, or the earliest substantive environmental compliance deadline.
- UCE states that "in the current IRP, the Company failed to analyze the costs and consequences of retrofitting (versus retiring) its large fleet of aging coal plants with pollution control equipment necessary to bring them into compliance with current and pending environmental regulations."

With respect to environmental compliance costs and coal unit replacement analysis, the Company provides a Confidential Supplemental Coal Replacement Study (Coal Replacement Study) filed along with these reply comments, which updates and expands upon the original coal utilization study conducted for the IRP. The Company developed this study to support its Wyoming application for a Certificate of Public Convenience and Necessity (CPCN) for Naughton 3 pollution control investments. The Coal Replacement Study uses the System Optimizer capacity expansion model to (1) test the economic merit of continued use with environmental retrofits against retirement and optimized portfolio replacement, (2) evaluate the risk of retirement under different cost scenarios, and (3) allow feasible replacements as of the earliest substantive environmental compliance deadline. This supplemental analysis reaffirms the findings of the coal utilization sensitivities performed for the IRP, and shows that the Company's coal resources, with planned incremental investments, will continue to provide reliable and least-cost electric service to customers in alignment with the IRP preferred portfolio and action plan.

PacifiCorp has also committed, via the IRP action plan, to continue to assess emerging environmental regulations and their potential impacts on the Company's coal-fired generation resources. The coal utilization case studies in the IRP were the first step in meeting PacifiCorp's obligation in that regard, involving new model functionality that combines incremental plant investments and coal plant shutdown optimization. It should not be presumed, however, that accelerated closure of the Company's coal fueled generation resources is inherently in the best interests of customers. While that outcome would align itself well with the interests of certain commenting parties, the Company's assessments to date have not supported that result. As the Commission is aware, the Company assesses the depreciable plant lives for ratemaking purposes of each of its facilities every five years, with the next assessment scheduled to begin in 2012.

Finally, PacifiCorp's emissions control investment program, and investments in individual generation units, cannot be considered in isolation. As discussed in PacifiCorp's IRP, the Company's preferred portfolio outcomes must balance the need to effectively manage its existing generation resources and identify the most appropriate mix of new generation resources to meet its generation capacity deficit. In addition to reducing emissions and maintaining least-cost generation availability from the existing facilities at which it has invested in emissions control equipment, the Company has also avoided increasing emissions by adding more than 1,400 megawatts of non-emitting wind generation between 2006 and 2010 and implementing demand-side management programs.[2] During that same time period, the Company has also invested in natural gas fueled resources, the most significant of which are the Company's Currant Creek block 1 combined-cycle combustion turbine (CCCT) facility that was placed in service in March 2006, the Company's Lake Side block 1 CCCT facility that was placed in service in September 2007, and the Chehalis CCCT facility acquired in September 2008. PacifiCorp has also recently begun construction of the Lake Side block 2 CCCT facility that is scheduled to be placed in service in 2014.

Wind Resource Modeling Assumptions

WRA, OCS and UCE comment on the wind resource assumptions used for portfolio modeling. They believe that the Company's modeling assumptions "handicap" or "restrict" wind resource selection. The following are the alleged problems identified by the parties.

- WRA claims that the Company's wind turbine costs are too high.
- OCS, WRA, and UCE claim that by delaying wind acquisitions to 2018, the Company may miss opportunities for cost-effective wind opportunities.
- UCE alleges that wind resource selection forces incremental investment in Energy Gateway transmission.
- OCS, WRA, and UCE believe that the Company's 200 MW annual wind additions limit is unduly restricting wind resource selection.
- WRA and UCE find fault with the Company's decision to not include an unbundled Renewable Energy Credit (REC) revenue credit applied to wind resource costs.

<u>Wind Capital Costs</u>

With respect to the claim that wind turbine costs are too high, PacifiCorp provided its analysis of the Interwest Energy Alliance (IEA) capital cost recommendations for east-side wind resources

[2] According to a March 2011 report issued by Zpryme Research & Consulting, LLC, PacifiCorp ranks among the top 10 electric utilities in the U.S. based on program investments from 2005 through 2010. The report is available for download using the following Web hyperlink:
http://smartgridresearch.org/wp-content/uploads/sgi_reports/Top_10_US_Utilities_by_DSM_Investment_Zpryme_Smart_Grid_Insights_March_2011.pdf

in the IRP Addendum filed June 27, 2011.[3] PacifiCorp found no basis to conclude that its wind capital costs were inappropriately high as claimed by IEA. One factor mentioned by PacifiCorp is that regardless of wind turbine cost trends, other wind development costs will increase due to the need to exploit increasingly less desirable sites along with burgeoning environmental regulatory constraints. Unfortunately WRA did not respond to the Company's specific findings outlined in the 2011 IRP Addendum or provide additional evidence supporting lower wind capital costs.

Timing of Wind Additions

Regarding the comments on wind timing and pursuit of economic resource opportunities, the parties appear to be confusing the role of the IRP with that of the procurement process. The Company responded to an OCS data request on this issue. OCS asked PacifiCorp to "identify and fully describe all constraints that limit the Company's ability to acquire new wind resources until 2018."[4] The response was as follows:

> Wind resources cannot be acquired in Wyoming until the 2018 expected completion of the Windstar-Populus segment of the Energy Gateway plan due to the lack of transmission transfer capability for exporting the energy. For locations outside of Wyoming, the constraints are principally economic in nature. Wind resources outside of Wyoming are not cost-effective based on the Company's capacity factor and capital cost assumptions, a result confirmed by the IRP portfolio modeling. The Company would not expect to get cost recovery for wind acquisitions with such higher costs unless those resources were needed to comply with stricter state renewable portfolio standards or new federal renewable targets along the lines of Waxman-Markey. The likelihood of such standards being enacted and requiring significant renewables acquisitions by the Company for 2015-2017 is small given the current economic and political environments. *Notwithstanding these constraints, the Company may acquire non-Wyoming wind prior to 2018 through PURPA Qualifying Facility contracting or other procurement opportunities if advantageous for customers* (emphasis added).

PacifiCorp reminds the parties that the purpose of the IRP is not to evaluate the economics of specific generation projects. As mentioned on page 252 of the IRP, the preferred portfolio does not constitute resource acquisition commitments. To underscore the distinction between resource planning and procurement processes, the Company refers the parties to the renewable resource procurement strategy described in the *Action Plan* chapter of the IRP (page 273) and the Acquisition Path Decision Mechanism section (page 266).

Energy Gateway Transmission Investment Costs

UCE's claim that wind resource selection forces incremental investment in Energy Gateway transmission is incorrect. The Company only assigned the incremental transmission costs needed to interconnect the wind with the grid, not the Energy Gateway segment costs. The IRP mentions

[3] The IRP Addendum can be accessed using the following Web hyperlink: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-Addendum_20110627.pdf

[4] OCS Data Request 2.4.

that this cost assignment was accomplished with the use of "wind-generation-only" transmission bubbles in certain cases. For Energy Gateway scenario 1, which only includes the Energy Gateway Central segments, a large investment in west-side transmission would be needed to support at least 500 MW of additional wind in Washington and Oregon. As discussed on page 128 of the IRP, PacifiCorp did not use a wind-generation-only bubble to assign costs for this transmission scenario; rather, a cost adjustment was applied to the total portfolio PVRR after the model determined the portfolio solution. As a result, neither the Energy Gateway transmission costs nor the west-side incremental transmission cost adjustment applied for Energy Gateway scenario 1 had any effect on the quantity of wind selected by the model.

Annual Wind Additions Limit

PacifiCorp emphasizes that the 200-megawatt annual wind capacity constraint is a planning assumption, not a hard limit on actual wind resource acquisition as the parties seem to believe. PacifiCorp responded to an OCS data request on this issue as well.[5] The Company response was as follows:

> The wind capacity smoothing approach embodies the planning preference of the Company to acquire wind on a steady and predictable basis rather than in large quantities on an infrequent basis. The reasons are cited in both the 2008 and 2011 IRP documents. This smoothing is intended as a long-term planning assumption rather than a precise prediction of how the Company expects to acquire wind. As noted on page 227 of the 2011 IRP, actual wind acquisition "will be determined as an outcome of government mandates and constraints, transmission availability, technology costs, and the Company's renewable procurement process."

Unbundled Renewable Energy Credit Revenues

PacifiCorp believes that excluding unbundled REC revenues from renewable resource costs is an appropriate long-term planning assumption if some form of carbon regulation is also a long-term planning assumption. In the short term, selling excess RECs in advance of RPS generation targets may result in reduced customer costs. However, the impact on long-term renewable resource costs is negligible. Additionally, considerations such as (1) risk of modified or more stringent RPS requirements, (2) relative benefits of banking excess RECs versus selling them, and (3) the speculative nature of estimating unbundled REC values, makes REC revenues difficult to address in the IRP modeling context.

Treatment of Geothermal Resources

OCS and UCE comment on PacifiCorp's handling of geothermal resources for preferred portfolio development. OCS believes that removal of geothermal resources from the preferred portfolio and replacement with wind resources (adjusted to account for capacity factor differences) is unjustified. While UCE acknowledges the Company's concerns with resource development risk, it believes that the results of IRP modeling support amending the action plan to include acquisition of geothermal resources in the near term.

[5] OCS Data Request 2.6.

PacifiCorp recognizes the potential advantages of geothermal resources as a clean and cost-effective baseload option if development risks for the Company and its customers can be appropriately mitigated. It is important to note that the Company has not eliminated geothermal generation from consideration even though this resource was excluded from the preferred portfolio. In fact, the IRP identifies geothermal acquisitions "of up to 105 MW" as an alternate resource procurement path (page 224). Page 131 of the IRP also summarizes the Company's plans to continue analyzing geothermal opportunities, which is reflected in the IRP action plan on page 254. For example, the Company will shortly issue a Request for Information (RFI) for geothermal developers within and near PacifiCorp's service territory with the following objectives:

- To identify projects that PacifiCorp may consider as a project co-developer or participant
- To identify what types of commercial structures or resources are needed to facilitate development of geothermal resources
- To assist both PacifiCorp and the state regulatory agencies to identify the level of development and viability of geothermal resource opportunities.

The Company also indicated in the IRP action plan that it will continue to include geothermal projects as eligible bids in future Requests for Proposals (RFPs).

Energy Gateway Transmission Modeling and Project Justification

OCS, UAE, and WRA identify perceived weaknesses or limitations of the Energy Gateway transmission scenario modeling as it relates to supporting remaining transmission investments and the preferred portfolio and associated wind resources in Wyoming. OCS believes that "[b]y hardwiring the full Energy Gateway project and more expansive renewable requirements into the final IRP modeling process, the Company essentially has predetermined a resource future, i.e., wind in Wyoming." UAE claims that PacifiCorp has not adequately shown that the remaining segments of the Gateway Transmission project are cost effective or in the public interest, and that the System Optimizer model "is not the right tool for evaluation of optimal transmission additions" because of its limitations. UAE also states that allocation of transmission costs should be evaluated and resolved by the Commission before any further transmission expenses for the Gateway project are approved." WRA suggests that PacifiCorp used inconsistent modeling assumptions to develop its core case portfolios and for its Energy Gateway segment analysis.

<u>Linkage of the Full Energy Gateway Footprint and Wyoming Wind Resources</u>
As OCS points out in its comments, there is an interdependent relationship between the need for significant amounts of new wind resources and new transmission capacity. Chapter 4 of the Company's IRP, "Transmission Planning", thoroughly explores this relationship and the assumptions that would lead to the need for such resources and associated transmission capacity. An important distinction, however, is that the preferred portfolio and the Company's Energy Gateway transmission program are based on the Company's assumption that there will be continued penetration of renewable and low-carbon resources into the foreseeable future (i.e. a "Green Resource Future"). Due to the long lead-time and hurdles to building transmission, and the significant regulatory risk associated with not having sufficient transmission capacity when it is needed, assumptions must be made in order to support such a future. PacifiCorp welcomes input from regulators and other stakeholders on the reasonableness of its assumptions. The

Company took this approach in the IRP in anticipation of on-going scenario planning within the interconnection-wide transmission planning process funded by U.S. Department of Energy. PacifiCorp's interpretation of that process is that potential future scenarios with policy assumptions will be translated into quantifiable study cases which will show impacts to transmission and resource needs. As highlighted by parties' comments, both in the IRP and the broader planning effort, aligning assumptions on the future scenarios will be a critical step in the overall process. PacifiCorp looks forward to the opportunity to further develop those assumptions with parties in future IRPs. The Company views acknowledgement of the IRP for PacifiCorp as a recognition of possible, plausible futures the Company should be planning to support rather than an endorsement of specific segments of Energy Gateway. The Company has committed to use the proper regulatory processes to justify and gain approval of individual segments at the appropriate time.

OCS suggests that the economic prudence of the planned Wyoming wind resources depends on "potential and uncertain increases in RPS standards, carbon taxes and fuel prices." As the IRP acknowledges in Chapter 4, the uncertainties surrounding federal regulation of CO_2 emissions and potential new state and/or federal renewable energy requirements do not defer PacifiCorp's obligation to plan for and meet its customers' future electricity needs. The Company's planned transmission additions not only support the "Green Resource Future" discussed in Chapter 4, but are well aligned with rich and diverse resource areas throughout the Company's service territory, including areas identified in the IRP preferred portfolio for an additional 1,800 MW of combined cycle natural gas generation, combined heat and power, and solar generation. These projects represent PacifiCorp's best estimation of the resources that will be needed to cost-effectively and reliably meet its customers' needs over the long term. Again, PacifiCorp requests input on its assumptions.

Finally, OCS recommends that "this analysis should not be seen as sufficient to justify need for the next segments of the Gateway project." The Company agrees and points to its statement in IRP Chapter 4, page 63:

> "Each segment will be justified individually within the overall program. A combination of benefits, including net power cost savings derived from the IRP, reliability, capital offsets for renewable resource development in low yield geographic regions and system loss reductions will be used to assess the viability of each segment... Each Energy Gateway segment will be re-evaluated during the Company's annual business plan and IRP cycles to ensure optimal benefits and timing before moving forward with permitting and construction. Depending on conditions or alternatives, certain segments could be deferred or not constructed if evaluations prove the need or timing has shifted."

PacifiCorp is fully committed to demonstrating the need for each of its proposed transmission projects through the appropriate regulatory processes, which include a Certificate of Public Convenience and Necessity to demonstrate need, a project pre-approval application through the voluntary process in the Energy Resource Procurement Act and/or general rate case to establish prudence. At this time, focusing only on the IRP process, the Company seeks the Commission's input on the public policy assumptions used to justify the transmission resources proposed in PacifiCorp's 2011 IRP preferred portfolio.

Transmission Expansion Modeling using System Optimizer

UAE believes that the System Optimizer capacity expansion model is not suitable for Energy Gateway analysis because of functional limitations identified in the IRP by PacifiCorp. These limitations include not being able to (1) optimize transmission expansion for a situation in which one transmission option is dependent on another, such as for rating support (IRP page 67), (2) capture stochastic risk (IRP page 75), and (3) accurately represent certain transmission operational constraints such as Remedial Action Schemes (IRP page 75).[6]

PacifiCorp underscores that no system simulation model can account for all operational or location-specific details on an optimal basis, particularly given the complexity of modeling PacifiCorp's system and the long-term (at least 20-year) focus of integrated resource planning. Nevertheless, the Company believes that it has adequately compensated for the model limitations identified in the IRP by making suitable manual adjustments and using the Planning and Risk production cost model for capturing stochastic risks. Moreover, the Company emphasizes that Energy Gateway project justification, as well as justification for any other resource, does not hinge on the results from one model. Energy Gateway has undergone continual evaluation using System Optimizer, the Planning and Risk production cost model, and other planning tools. Each model is suited for evaluating particular aspects of transmission investment and its system impacts. For example, System Optimizer's forte has been to gauge economic and generation resource timing and location impacts of alternative Energy Gateway configurations under different natural gas and regulatory policy futures. Thus, it is PacifiCorp's opinion that the use of System Optimizer is appropriate and sufficient for evaluating the "public policy" future scenarios outlined in Chapter 4.

Energy Gateway Cost Allocation

UAE states that "Captive Utah retail ratepayers should not be expected, and cannot afford, to fully underwrite expensive and risky transmission ventures designed to benefit others."[7] UAE's comments regarding Energy Gateway's design and cost allocation reflect a fundamental misunderstanding of the cost allocation process. Energy Gateway transmission has been sized and is being built to meet the needs of PacifiCorp's network customers—the largest of which, by far, is PacifiCorp Energy, which uses the transmission system to provide service to the Company's retail customers. As those needs change so will the timing, scale and segments proposed within the Energy Gateway program. UAE's comments also overlook that FERC Open Access rules require the Company to plan and build the transmission system for all of its network customers, and that all retail and wholesale customers pay for use of the transmission system. Additionally, all revenue received from third-party wholesale customers comes back as a dollar-for-dollar credit to retail customers—meaning each customer class pays its share for use of the

[6] On page 76 of the IRP, PacifiCorp discusses import capability adjustments made to avoid capacity deficits in certain topology bubbles that result from the topology design and not actual physical transmission constraints. Such adjustments are an inherent aspect of simplifying the representation of PacifiCorp's transmission system for long-term simulation purposes, and not indicative of a model deficiency.

[7] UAE Comments, p. 2.

transmission system, and retail customers are not required to bear the cost associated with third-party wholesale use.

Wind Integration Study

Three parties, OCS, WRA, and UCE, address PacifiCorp's 2010 wind integration study. The parties cite claimed technical flaws with the study and the limited amount of time for stakeholder review, and recommend that the Commission require the Company to conduct another wind integration study that addresses stakeholder concerns and uses a technical review committee.

In response to these concerns and recommendations, the Company notes that the IRP action plan includes an action item for wind integration analysis:

> Continue to refine the wind integration modeling approach; establish a technical review committee and a schedule and project plan for the next wind integration study.[8]

The Company will continue to investigate methodological concerns raised in the public input meetings and written comments for the next wind integration study. However, it is premature to claim, as some of the parties do, that PacifiCorp's wind integration cost should be significantly less than the value published in the 2010 study.

Regarding concerns on the handling of the public process and data verification, it should be stressed that wind integration analysis is an evolving activity for the Company and electric utility industry in general, and that PacifiCorp developed a fundamentally new methodology in response to comments from the prior wind integration study. It took much longer than expected to analyze data, develop simulated data for wind resources, create and test the wind reserve estimation model in coordination with the Company's technical advisor, and perform the numerous production cost simulations. With commitments for the public process and firm deadlines to incorporate study results in IRP portfolio modeling, the Company nevertheless achieved its study objectives and produced a wind integration cost reflecting important methodological improvements over previous study efforts.

Long-Term Load Volatility Parameters

WRA and OCS express concern regarding PacifiCorp's decision to set long-term load volatility parameters to zero. WRA claims that it did so without consulting with public participants, and states that public participants only "became aware of the change upon reviewing the draft document."[9] OCS states that Company did not perform any sensitivity analysis that tested the impact of setting the long run load volatility parameters at different levels, and thus "has not justified whether this change enhances or diminishes the robustness of its risk analysis." OCS further recommends that "Ventyx provide a technical paper explaining why it endorses this modeling change, the implications of this change for risk analysis and whether this change has been recommended to and adopted by other clients."

[8] 2011 IRP, Chapter 9, p. 257.
[9] WRA Comments, p. 14.

WRA's claim that PacifiCorp did not discuss the long-term load volatility parameters with public participants is wrong. The Company presented its reasons for setting these parameters to zero at the December 15, 2010 public input meeting, and notes that representatives from WRA did not attend this meeting. It is also apparent WRA did not review the presentation sent prior to this meeting or the subsequent IRP public input meeting report distributed to IRP participants in January 2011. These meeting materials clearly identify the long-run load volatility parameters as a discussion topic.

In regard to the rationale for setting the long-term load volatility parameters to zero, PacifiCorp provided a detailed justification on page 188 of the IRP:

> The underlying causes of long-term load changes are fundamental shifts in: technology (e.g., electric cars); demographics (e.g., population); fuel switching (e.g., switching from gasoline engines to electric motors); DSM (e.g., energy efficiency, appliance standards); and economic growth. These long-term shifts require a solution that allows capacity change. But, PaR cannot re-optimize its capacity additions, which creates a problem when dispatching to meet the more extreme load excursions often seen in long-term stochastic modeling. Since capacity is not fixed in the long term, this constraint yields an inefficient static solution. Additionally, several public stakeholders have raised concerns regarding out-year resource impacts on near-term resource selection and investment for capacity expansion modeling using System Optimizer. Large load excursions in the out years, driven by the long-term load volatility parameter, represent a parallel example of out-year resource influence on portfolio cost. These observations, coupled with the fact that loads are, by nature, somewhat bounded in the upper tail, led PacifiCorp, in consultation with its model vendor, Ventyx, to refine the stochastic modeling process by setting long-term load volatilities to zero.

Ventyx was notified that the Company was obtaining unrealistically large load excursions in the out years of the production cost simulations, and was considering such options as eliminating outlier run iterations from the Present Value Revenue Requirements (PVRR) calculations and reducing the long-term volatility parameters. Ventyx informed the Company that the approach recommended to other clients having similar issues was to set the parameters to zero. This strategy recognizes that establishing alternative, non-zero parameter values would be a subjective undertaking because there would be no empirical basis for estimating them. It thus follows that OCS's suggestion to conduct sensitivity testing on different volatility parameter levels would not indicate what level is best or reasonable.

Finally, the strategy of setting long-term load volatility parameters to zero recognizes that structural changes driving large and permanent long-term load trend changes are best modeled as a System Optimizer risk scenario rather than a stochastic process for production cost modeling. In other words, a real-world response to shifting long-term electricity demand trends is to optimize capacity additions rather than accept an everincreasing risk of electricity shortages, which is what the stochastic production cost model is constrained to do.

Planning Reserve Margin Level

OCS and UAE comment on the change in the target capacity planning reserve margin (PRM) from 12 percent to 13 percent. OCS agrees in principle with the PRM increase and using the Loss of Load Probability (LOLP) study to support that decision. However, OCS believes that the Company should provide its own analysis of benefits from the Northwest Power Pool's Contingency Reserve Sharing Program (CRSP), and believes that a higher PRM (between 13.5% - 14.0%) is reasonable. UAE argues that a PRM increase is not warranted or affordable given retail rates increases, and states that "the proposed 1% increase in planning reserve alone drives a projected need for an additional gas plant during the planning horizon."

Regarding the Contingency Reserve Sharing Program and its impact on setting the PRM, PacifiCorp agrees that its own modeling analysis is needed as the next step. As indicated in the IRP, modeling this program is not straightforward. For the next IRP, the Company intends to consult with Ventyx on adopting a reasonable approach for representing CRSP impacts in production cost modeling.

UAE's claim that the one percentage point increase in the PRM (from 12 to 13 percent) drives the need for an additional gas plant is incorrect. The capacity difference between a 12 and 13 percent planning reserve margin is about 90 MW on a system basis and 65 MW on the east side, since reserves are not held for Class 1 DSM, firm market purchases, and firm interruptible load contracts. Additionally, these incremental reserve amounts could be met with a variety of resources, including low-cost DSM and distributed generation.

IRP Model Tutorial and Model Accessibility

DPU stated that the Company's IRP model tutorial held July 12, 2011 "fell significantly short of expectations" in that a presentation was not sufficient to allow parties to verify assumptions and results. UAE states in their comments that "the quality of public input would be significantly increased if the regulators and other interested parties were permitted access to operate the modeling tools for verification of the models, the output data and how results change via inputs."[10]

Regarding the IRP model tutorial, the Company considered it important to first provide foundational IRP model and modeling process background information, particularly given stakeholders with varied levels of exposure to, and experience with, PacifiCorp's resource portfolio modeling. The Company notes that it met with the Utah parties at the conclusion of an IRP public input meeting in 2010 to discuss expectations for IRP model training. It proposed to focus on basic model functionality, model operation workflow, and output reporting. Because of the complexity of the models, the extensive training and experience needed to become a competent model operator, and the non-portability/proprietary nature of the models, the Company believed that this training focus was appropriate before attempting to delve any deeper

[10] UAE Comments, p. 8.

into model operations. The Utah parties appeared to agree with this overall approach. Consequently, the Company designed the model tutorial session with this goal in mind, and believes it provided meaningful and useful information based on positive responses from several participants at the conclusion of the one-day meeting.

Concerning expectations for model and assumption validation, the Company believes that such validation is a long-term iterative and multifaceted process rather than an end result obtained at a meeting. To demonstrate model credibility and reliability on a comprehensive basis, the Company and public stakeholders would need to do the following:

- Develop test plans and protocols for conducting the necessary benchmarking, sensitivity, and historical forecast tests for each model (System Optimizer and Planning and Risk).
- Identify who is to conduct the validation; if public stakeholders expect to do it, as UAE recommends, Ventyx training and access to a test environment (involving potential payment of software license fees), are prerequisites.
- Develop a project plan with a reasonable schedule, along with a public process for feedback and results sharing.
- Determine if there should be "next steps" as the outcome of the validation project, such as developing alternative input formulations or modeling approaches to address modeling issues identified.

As these requirements indicate, such a validation effort could be highly complicated and time-consuming. Most importantly, it is unnecessary because the models have been monitored and tested on a long term basis by PacifiCorp and other Ventyx clients. The Company would be concerned about the disruptive impact on the IRP schedule of such a project, as well as dependence on stakeholder time commitments that may not materialize due to changing priorities and obligations.

A reasonable approach going forward for model validation would be for stakeholders to identify at the next IRP kick-off meeting specific modeling or assumption development concerns for which the Company could investigate based on a clearly defined scope of work, and in consideration of scheduling and analytical priorities. The investigation could involve model runs, consultation with Ventyx, or other approaches. Such a validation strategy would be an on-going process for future IRPs rather than a one-time project targeted for completion by a certain date. This makes sense given continuously evolving models and study requirements.

For those stakeholders that want to use and understand the models better, Ventyx's policy for outside parties to gain access and use the IRP models is for the outside party to purchase an "engagement license" and training services. As of mid-2010, the estimated software license cost for both models is in the range of $8,000-$10,000 per month. A five-day training program is required, and the estimated cost of this training is about $9,000. Finally, an outside party would need to show proof of minimum specification hardware. In the case of the Planning and Risk model, the outside party would also require the Microsoft SQL Server database server system and have requisite experience installing, configuring, and operating client-server applications as well as database administration expertise.

4. REPLIES TO OTHER PARTY COMMENTS

Division of Public Utilities

Hedging Risk and Cost Analysis
DPU believes the Company's hedging analysis documented in Appendix G of IRP Volume II has not complied with the Commission's requirements, and identifies two areas viewed as being deficient:

- PacifiCorp did not include gains and losses associated with electricity and natural gas hedges in the analysis, while inclusion of only transaction costs (brokerage fees) is "incorrect and misleading." For example, the company has not included the costs associated with mark-to-market price changes and thus did not recognize the "total fuel price" for natural gas.
- While the hedging analysis looked at volatility, it did not address how the Company's current strategy minimizes cost as required by the Commission.

Regarding the handling of gains and losses associated with electricity and natural gas hedges, the Company believes that the expected gain or loss of an electricity or natural gas hedge, evaluated prior to the execution of the hedge, is best estimated to be zero. This is due to the lack of foreknowledge of settlement prices at the time of hedge execution and that hedging only reduces the range of potential net power costs not the expected value. The Company thus maintains that it reasonable to only include broker fees, collateral funding and bid-ask spreads when assessing the cost of hedging.

Concerning the objective of minimizing both hedging costs and risk, the Company continues to maintain that there is no objective method or measurement to indicate the optimum amount of hedging; rather, the focus should be on optimal hedging program management in light of such factors as customer risk tolerance, market liquidity, and types and availability of desired hedge products. The Company can nevertheless reduce hedging costs by managing broker fees, by managing credit risk, and by transacting liquid products.

The Company is currently addressing hedging issues as part of the agreed-to "collaborative process" with Utah stakeholders established as part of the Utah general rate case stipulated settlement, and believes this is the proper forum to discuss the fundamental conceptual disagreements among parties concerning hedging theory and practice.

Office of Consumer Services

Least-Cost/Least-Risk Justification for the Preferred Portfolio
OCS identified a number of issues associated with the preferred portfolio (referred to as the "re-optimized Case 3" portfolio). Some of these issues pertain to wind resource modeling assumptions, and were thus addressed by the Company above. The additional issues identified by OCS include the following:

- The Company has not adequately demonstrated that its preferred portfolio represents a low cost, low risk and reliable set of resources, and recommends that PacifiCorp apply the new "renewable resource policy" criteria to all core case portfolios and provide the results to the Commission and other stakeholders. OCS also asserts that the re-optimized Case 3 portfolio "appears to be a backdoor attempt to align the IRP outcome with the Business Plan, despite the fact that the business plan case failed to pass muster in the initial stochastic analysis."
- OCS states that "[t]he Re-optimized Case 3 inflates geothermal resources to 500 MWs and then replaces geothermal with 1,300 MWs of 'geothermal-equivalent' wind resources…", and then claims that this was done "without analytical justification."

PacifiCorp believes that OCS misunderstands the purpose of the wind resource adjustment and its linkage to resource optimization modeling and preferred portfolio development. The wind resource adjustment is meant to be a strategic hedge in response to public policy and regulatory uncertainty regarding renewables and environmental matters. Because there is no way to determine if such a hedge against uncertainty is optimal until after the long-term policy/regulatory outcomes are known, cost-risk optimization is not a pertinent framework for judging its efficacy. Rather, the criteria of whether it is "in the public interest", accounts for "social concerns" (IRP Guideline 4.g), promotes resource diversity[11], and supports planning flexibility, are the most germane considerations for justifying it.

From a portfolio modeling perspective, applying the renewable resource adjustment uniformly to all core portfolios would provide no useful information for informing preferred portfolio selection because the adjustment would reduce resource mix and cost differences across the portfolios, and thus making it more difficult to distinguish relative performance. It would, however, create a significant and unnecessary burden for the Company as well as generate another round of administrative activity for the Commission and other parties.

Finally, the Company clarifies that modeling of federal RPS requirement and renewable production tax credit (PTC) modeling constraints was used to help determine an annual distribution of wind quantities and not to directly "re-optimize" the preliminary preferred portfolio as OCS suggests.[12]

Regarding the handling of geothermal resources for the preferred portfolio, OCS is incorrect in claiming that PacifiCorp inflated geothermal capacity to 500 MW. Rather, it converted the 220 MW of geothermal capacity in the Case 3 portfolio to 572 MW of comparable wind capacity based on the capacity factor differences between the two resources. The justification for this treatment of geothermal resources is described earlier in this reply comments document.

Energy Efficiency (Class 2 DSM) Resources

[11] The Commission order for Docket No. 06-999-03, "Determination Concerning the PURPA Fuel Sources Standard", issued March 13, 2007, directs the Company to address resource diversity in its IRPs.
[12] OCS states on page 8 of their comments: "The 'Waxman-Markey RPS' and 'PTC extension to 2020' renewable policy assumptions were only applied by the Company to 're-optimize' the initial Case 3 to a portfolio that included considerably more wind resources.

While OCS commends the Company for its aggressive pursuit of Class 2 DSM additions, it is concerned that the DSM targets may not be "achievable, economical and fair to customers."[13] It makes the following recommendations:

- There should be a stronger tie between Class 2 DSM resource procurement planning and the IRP. The IRP should provide more detail on how the Company intends to acquire Class 2 DSM resources at these higher levels.
- The Company should provide an analysis of program incentives including the cost and equity impacts on customers.

In response, the Company believes that there is already a strong tie between the IRP and DSM procurement planning efforts. First, the DSM department works closely with the IRP department to ensure that Class 2 DSM supply curves, developed by The Cadmus Group, reflect practical yet aggressive implementation expectations in line with program experience in each state as well as state commission resource evaluation criteria. (Examples include Utah's use of the Utility Cost Test and Washington's conservation compliance regulations stemming from Ballot Initiative 937.) This is accomplished by adjusting annual potential amounts according to "market ramp rates" that are based on consideration of company-specific implementation constraints. An explanation of the market ramp rates is provided on pages 50-51 of the 2010 DSM potential study, while a graphical representation of the differing rates (Figure 17) is provided on page 51.[14] Preliminary portfolio modeling results are then shared with the DSM department to ensure that annual DSM resource amounts selected as being cost-effective are also attainable. Second, the IRP department conducts a Class 2 DSM decrement study for each IRP, the purpose of which is to value the resources' energy and capacity benefits to assist in the DSM department's subsequent procurement activities.

Nevertheless, there are aspects of DSM procurement/implementation that are appropriately not in the purview of integrated resource planning due to the treatment of DSM as situs resources in each state and the associated rate-making and other regulatory processes involved. In regards to program incentives and other cost considerations, the Company provides program-specific assumptions and cost-effectiveness results on a prospective basis when programs are introduced or modified, and retrospectively "as run" in annual reports and program impact evaluation results. Supporting materials such as market characterization studies, third party evaluation results, and other relevant market data is provided to stakeholders and Commissions in the states where the programs are offered. The Company and stakeholders also engage in dialogues as part of DSM advisory group and ad hoc working group (e.g. the Utah DSM Rate Design Working Group) activities. This is the appropriate forum to address customer cost and equity issues related to the pursuit of resources.

Cost of Energy Not Served

OCS believes that PacifiCorp's "tiered" pricing for Energy Not Served (ENS), described on page 199 of the IRP, "continues to understate the possible impact on customers of not having adequate resources to meet loads." OCS thus recommends that the Commission direct the Company to use

[13] OCS Comments, p. 14.

[14] The DSM potential study can be accessed from PacifiCorp's Web site, at http://www.pacificorp.com/es/dsm.html.

the more traditional FERC price cap approach for valuing the impact of ENS when comparing portfolios in the stochastic analysis.[15]

PacifiCorp believes that it is most appropriate to address the issue of assumed ENS prices for stochastic production cost modeling as a discussion topic at an IRP public input meeting rather than have the Commission dictate the value. The selection of an ENS price is a subjective determination, while the concept of ENS price itself can have more than one interpretation. For example, ENS price can refer to the value (or opportunity cost) of the energy not served, or, alternatively, the direct cost of obtaining replacement power. It may be appropriate to report a range of ENS costs for portfolios if PacifiCorp and stakeholders can agree on the bookend ENS prices.

<u>Load Forecasting Recommendations</u>
OCS contracted with GDS Associates, Inc. (GDS) to critique the Company's long-term load forecasting. OCS presents GDS's recommendations as Attachment 1 to their IRP comments. PacifiCorp responds below to each of the GDS recommendations identified with italics.
PacifiCorp should obtain and examine economic forecasts from one or two vendors in addition to IHS Global Insights. Multiple economic forecasts will help the Company recognize if a particular economic projection is too optimistic or pessimistic relative to its peers and should help provide a consensus forecast.
The Company recognizes the efficiency of having a single provider of economic forecasts to keep costs down. The Company is also gathering information about other vendors to evaluate if it makes sense to provide multiple sources. In the future the Company will have better information to make a decision on how to proceed.

As recommended in the 2008 IRP, GDS continues to contend that use of a measure of commercial and industrial output (e.g., retail sales or gross regional product) would be a better theoretical driver in the commercial and industrial sales models. Even if these variables have slightly worse model fit than using employment, they should still have acceptable statistical fit. If not, then continued use of employment would be appropriate.
The Company continues to investigate using different economic drivers, including the drivers recommended by GDS.

We recommend that PacifiCorp initiate an investigation into line losses for Utah and Oregon, specifically, and for any other jurisdictions that exhibit a strong trend over the last seven years. The Company should try to identify the cause of the trends and develop line loss projections based on that knowledge. The projections may include trends or shorter moving-averages in the short term.
The Company disagrees with the assertion that there are any significant trends in line losses as discussed in the rebuttal testimony of Mr. Duvall in the last general rate case (Docket No. 10-035-124) and would also note that in its June 2009 report, GDS stated the following:

> The Company used a five-year average of line loss percentages as the forecasted line loss factor. This methodology is sound in the absence of any specific knowledge of operational or system changes that might impact losses (such as

[15] The WECC price cap increased to $1000/MWh on April 1, 2011.

> implementation of AMI, accounting changes, or changing out old wire). GDS often uses a five-year average line loss factor when preparing forecasts for its clients.[16]

Nevertheless, the Company will continue to monitor line losses in the future to identify any significant trends.

GDS recommends the Company review economic range forecasts prepared by other utilities and produce ranges that have greater uncertainty built into them as the forecast horizon expands. Such a range would demonstrate the Company's increasing uncertainty about load into the future, which will be a more useful tool in analyzing and stress-testing potential portfolios in the System Optimizer and PaR modeling.
The Company will solicit input from public stakeholders, at a future IRP public input meeting, on the range of forecast scenarios that appropriately captures long-term uncertainty. This aligns with the Company's strategy of setting long-term load volatility parameters to zero for stochastic modeling and relying on scenario analysis to capture extreme load trajectories driven by economic, demographic, and market uncertainties. The Company will also review other utility forecast ranges with an eye toward the reasonableness of its scenarios.

GDS recommends the Company move from a 1-in-10 year weather scenario to a 1-in-20 year weather scenario to produce an even more extreme weather case. As with producing a wider margin of uncertainty in the economic ranges, this will be a useful projection for portfolio analysis. Given that the forecast is a 20-year outlook, it makes sense to test a 1-in-20 year weather event.
The Company is not opposed to developing a 1-in-20 year weather scenario for portfolio modeling. It will seek public input on this recommendation along with other portfolio development scenarios proposed by the Company and its stakeholders at a future IRP public input meeting that covers load forecasting.

Utah Clean Energy

Use of Utility Scenario Planning as an IRP Tool
UCE requests that the Commission consider Utility Scenario Planning (USP) as a component of the IRP standards and guidelines, and references a paper published by the National Regulatory Research Institute (NRRI) promoting it as a resource risk management tool.[17] The follow table from the NRRI paper (page 5) summarizes the differences between the two planning approaches.

[16] GDS, "Evaluation of PacifiCorp's Load Forecast", June 17, 2009, p. 9.
[17] The Utility Scenario Planning paper can be access with the following Web hyperlink: http://www.nrri.org/pubs/multiutility/NRRI_utility_scenario_planning_mar11-07.pdf

Integrated Resource Planning Compared to Utility Scenario Planning		
	IRP	**USP**
What's the question?	What is the optimal mix of particular supply and demand resources to provide a least-cost set of resources to serve a particular future with relatively small differences? This is an optimization approach to resource planning.	What collection of resources allows the utility to meet acceptably a set of scenarios that define a broad set of plausible futures? This is a risk-management approach to resource planning, looking to serve multiple futures with a set of resources.
What's the view of the future?	The utility uses a limited set of forecasts to portray the future.	The plausible futures are diverse scenarios based upon key uncertainties. No single forecast drives the planning process.
What's the focus?	The focus is on the cost of different technologies and how the analysis changes over a set of probable assumptions (sensitivity analysis). The focus is, "What should I do, given a trend-driven view of the future?"	The focus is on identifying key uncertainties that define plausible scenarios. The focus is "What if?"
What's the preferred resource?	Preferred resources are the least-cost mix of resources to meet a particular view of the future, as tested under sensitivity analysis.	Preferred resources are a set of resources that provide an always-acceptable solution under widely different—but plausible—views of the future.

USP and PacifiCorp's current portfolio development process appears to be similar, with the only substantive difference being the extent of reliance on "game changing" scenario drivers. For example, PacifiCorp comes up with a range of futures with public input, and included such diverse futures as a "market stress" scenario (Appendix H in Volume II) and a "green resource future" for transmission expansion and renewables acquisition analysis (Chapter 6, page 66). Additionally, unlike the IRP characterization in the table above, PacifiCorp's preferred portfolio is not based on the least-cost resource mix given a particular view of the future, but rather considers cost/risk portfolio performance under the range of scenarios.

The Company and its stakeholders can discuss broadening the types of scenarios modeled for the next IRP. For example, the IRP action plan includes plug-in electric vehicles and smart grid technologies as potential scenarios to be discussed. If the Company decided to go forward with such "what if" scenario analysis, the scenarios would need to be proposed and defined, with stakeholder input, early in the IRP development process to enable sufficient time to understand the data development and modeling implications before the Company commits to performing the analysis. PacifiCorp would be concerned, however, with the step of then formulating a resource strategy "that produces acceptable results across all the scenarios."[18] This could effectively yield competing strategic planning outcomes and preferred portfolios if reconciling results of the "what if" scenarios with the more traditional IRP scenarios becomes difficult or controversial.

[18] NRRI Utility Scenario Planning paper, p. 8.

For this reason, PacifiCorp recommends that the Commission not change the IRP Standards and Guidelines to adopt USP as an additional planning tool.

Utility-scale Solar Installation Costs

UCE recommends that the Company refresh its characterizations of utility-scale solar resources based on the latest projections, as well as incorporate pricing data acquired from its Oregon solar RFP. UCE also compares PacifiCorp's reported cost ($233/MWh) with those reported by the investment bank, Lazard.

The capital and operating costs used in the 2011 IRP compares favorably to recent proposals received in response to the 2010 Oregon RFP for solar PV resources. Oregon RFP responses also included proposals for crystalline solar panels with and without single tracking. The capacity factor of 19 percent is indicative of solar sites in Oregon and Northern Utah with fixed panels. Single-axis tracking can increase the overall annual capacity factor by 2 to 4 percent percentage points, but will also increase costs by 20 percent or more depending on panel type and tracking mechanism. The Company notes key differences between UCE's quoted Lazard costs and PacifiCorp's reported costs, with the main ones having to do with cost of capital, fixed operation & maintenance costs, and capacity factor assumptions.

PacifiCorp will continue to update the costs of solar PV energy based on the recent proposals in Oregon as well as other on-going efforts to develop self-build projects in Oregon and Utah in future updates and IRPs. Additionally the magnitude and applicability of renewable subsidies will be highlighted to ensure cost transparency specific to the technology represented.

Western Resource Advocates

Evaluation of Carbon Dioxide Risk

WRA claims that "[t]he modeling of CO_2 risk for this IRP cycle does not capture the potential range of CO_2 outcomes."[19]

PacifiCorp disagrees with WRA's assessment of how the Company addressed CO_2 risk in the IRP. The Company included four "hard cap" CO_2 regulatory scenarios as part of its core case portfolio development, as well as included a hard cap scenario for its coal utilization study (Case 24). A hard cap approach is considered an aggressive emissions control strategy because it enforces a declining physical CO_2 emissions limit regardless of compliance cost. It is not clear to the Company why WRA chose to ignore these compliance scenarios when listing the inventory of CO_2 mitigation policies used for portfolio development.

Regarding the CO_2 prices used for stochastic production cost simulation, PacifiCorp sought public input on appropriate CO_2 price scenarios for conducting portfolio development and stochastic simulation, and adopted changes based on stakeholder comments. No parties, including WRA, objected to the final CO_2 price scenarios selected for portfolio modeling.[20] PacifiCorp also believes that it adequately captured scenario risk associated with a sudden and aggressive change in CO_2 regulatory policy through its analysis of renewable resource stochastic

[19] WRA Comments, p. 10.
[20] WRA declined to provide written comments on PacifiCorp's July 2010 draft portfolio development cases.

upper-tail risk mitigation benefits used to derive the 2,100 MW of additional wind in the preferred portfolio.

Forced Outage Modeling for Existing Thermal Plants

WRA states that "Unexpected forced outages at PacifiCorp's existing thermal plants were not modeled as a potential [stochastic] risk", and that the decision to model existing plants in this way deserves public vetting.[21]

PacifiCorp responded to a WRA data request in July 2011 on this matter.[22] The response provided is as follows:

> At the IRP Model tutorial meeting held July 12, 2011, the Company mischaracterized the role of Monte Carlo sampling for unit outage patterns for existing thermal units. The Planning and Risk (PaR) modeling does subject existing units to Monte Carlo draws. The Company changed the PaR probabilistic outage methodology for the 2007 IRP to address the occurrence of unit outage durations that far exceeded those actually experienced based on unit history. The alternate PaR methodology makes Monte Carlo random draws against partial availability states as well as a full outage state. The model user specifies probabilities of the amount of time that a unit is at certain capacity levels. PacifiCorp staff developed the state probabilities and capacity levels by inspecting daily outage histories of the units over a 48-month historical period. IRP thermal resource options simulated with the PaR model use the conventional Monte Carlo method where random draws are against the full outage state only. The only parameter for this probabilistic approach is the expected equivalent forced outage rate.

From this response, the Company made clear that it does apply stochastic outage modeling for existing thermal plants, but that the methodology changed several years ago to address unrealistic outage results. It appears that WRA wrote the comment above prior to reviewing the Company's data request response, or did not understand it.

Base Gas Price Forecast Consistency for Stochastic Modeling

WRA believes that PacifiCorp may not have applied the same natural gas price forecast for the stochastic simulation modeling, stating the following:

> Thus, portfolios that were built assuming a low natural gas price future were risk tested allowing for variability only around a low natural gas price forecast, and portfolios that were created using a high natural gas price future were risk tested allowing price fluctuations only around a high gas price future. If PacifiCorp indeed modeled stochastic risk using the same assumptions that were used to develop the portfolio, the disappearance of the cost/risk trade-off would be fully explained.[23]

[21] WRA Comments, p. 14.
[22] WRA Data Request 1.4.
[23] WRA Comments, p. 15.

WRA comes to this conclusion by inspecting the clusters of portfolios in IRP Figure 8.10 on page 216. They notice that many portfolios with a high cost (stochastic mean PVRR) were developed with the high natural gas price forecast scenario, whereas portfolios with a low cost were developed with the low natural gas price forecast scenario.

WRA's conclusion is incorrect; PacifiCorp applied the same natural gas price forecast scenario for all stochastic simulations. The distribution of portfolios by stochastic mean PVRR cost in Figure 8.10 is explained by the resource mixes selected as a result of the price forecast scenarios used for System Optimizer portfolio development. Going from low to high gas prices, System Optimizer reduces the number of CCCTs, and then needs to select higher-cost resources to address the capacity gap as well as replace gas plant generation that is no longer cost-effective.

Examining the resource differences between the Core Case 3 and 11 portfolios illuminates this model behavior, since the only difference in modeling assumptions for these two portfolios is that the Core Case 3 portfolio was developed with the low gas price scenario whereas the Core Case 11 portfolio was developed with the high gas price scenario. The Core Case 11 portfolio has one less CCCT (a 475 MW H-class 1x1 resource) than the Core Case 3 portfolio. To make up for the loss of the CCCT and replace uneconomic generation from other gas plants, the model selects an incremental 315 MW of geothermal resources, a 50 MW west-side utility-scale biomass plant, and 196 MW of additional Class 2 DSM. These replacement resources are more expensive than the CCCT, particularly with respect to fixed costs. WRA can verify this for the supply-side resources by inspecting Tables 6.3 through 6.6 in Chapter 6 of the IRP (pp. 117-120). Table 1 below compares the portfolio DSM Class 2 quantities and costs for the "Utah North" load area, which constitutes the bulk of the additional DSM in the Case 11 portfolio. As can be seen, the model adds about 144 MW of higher-cost Class 2 DSM in response to the higher gas prices.

Table 1 – Class 2 DSM Quantity and Cost Comparison, Core Case Portfolios 3 and 11 (Utah North)

Price Bundle Selected	Levelized Cost [1/] ($/MWh)	Installed Capacity (MW)		
		Case 11	Case 3	Difference
CFL	14	37.9	37.9	0.0
00-07	57	940.3	940.3	0.0
08-09	74	106.9	101.4	5.5
10-11	94	51.8	7.9	43.9
12-13	111	27.0	7.4	19.6
14-15	128	27.4	3.3	24.1
19-26	216	74.5	23.8	50.7
Totals		287.6	143.8	143.7

[1/] Modeled cost after applying cost credits documented on page 147 of the IRP.

In summary, WRA fails to consider resource type and cost differences among the portfolios simulated with the stochastic production cost model in reaching its conclusion.

Sierra Club

Inclusion of Environmental Externality Costs Associated with Thermal Plants
Sierra Club requests that the Commission require the Company to account for additional externality costs (i.e., health impact/premature mortality costs) for resource portfolio evaluation and acquisition. Sierra Club states that "there is abundant public data available on the damages incurred from coal generation on a unit by unit basis", and provides a prepublication copy of a study that is subject to further correction and an excerpt from a study that was not peer reviewed as two examples of externality cost studies in exhibits.[24]

PacifiCorp believes that incorporating costs associated with projects to maintain compliance with environmental regulations established by the EPA and other governing agencies prudently and appropriately addresses the potential effects of coal generation emissions on human health. Adding further externality cost adjustments, as suggested by Sierra Club, is not appropriate in IRP modeling analyses. The Company notes that the EPA and other governing agencies are specifically tasked with addressing such costs and health impacts as part of their regulatory oversight obligation to establish appropriate emissions control requirements for the power generation industry. For example, the EPA maintains National Ambient Air Quality Standards that are designed to be protective of human health and the environment. As stated above, the Company maintains compliance with such regulations and has incorporated the appropriate compliance costs into its IRP modeling effort. In addition, the Company's CO_2 tax assumptions, in the absence of carbon regulations, incorporate externality costs of thermal plant emissions not currently addressed by regulatory agencies.

Regarding the damages estimates cited by Sierra Club, the Company notes that the 2010 Utah "Co-Benefits" study cited by Sierra Club (as well as HEAL and Physicians for a Healthy Environment in their comments on the IRP draft document) was only intended to inform the Utah state agencies on energy efficiency and renewable energy deployment in the state, and that the state agencies that supported the study cautioned against using it and its findings for other purposes.

The Company is committed to maintaining compliance with all environmental requirements assigned to its operating facilities, including those that are established to protect human health and has incorporated compliance costs into the IRP.

5. CONCLUSION

PacifiCorp respectfully requests that the Commission acknowledge the 2011 IRP. It believes that the Commission's IRP Guidelines and Standards, IRP acknowledgment requirements, and action item obligations have been satisfactorily met, and that the IRP preferred portfolio and action plan are reasonable, reflect balanced consideration of customer interests, and is well-supported by portfolio modeling and prudent planning assumptions.

[24] Sierra Club Comments, p. 3. The exhibits referenced include: Exhibit 2, "Hidden Costs of Energy" and Exhibit 3, "Co-Benefits of Energy Efficiency and Renewable Energy in Utah."