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Division of Public Utilities

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**MEMORANDUM**

To: Public Service Commission

From: Division of Public Utilities
Constance B. White, Director
Artie Powell, Manager, Energy Section
Thomas Brill, Technical Consultant
Judith Johnson, Technical Consultant
Charles E. Peterson, Technical Consultant

Subject: *In the Matter of the Acknowledgment of PacifiCorp's 2006 Integrated Resource Plan*: Docket 07-2035-01 (Filed on May 30, 2007 as "2007 Integrated Resource Plan").

Date: August 31, 2007

**Recommendation:** The Division of Public Utilities recommends that the Public Service Commission not acknowledge PacifiCorp's Integrated Resource Plan and Action Plan. As explained below, the Division believes that PacifiCorp has not complied with the Commission's IRP Standards and Guidelines (Docket No. 90-2035-01, "Report and Order," dated June 18, 1992).

The Division appreciates the effort of PacifiCorp's IRP Team, the preparation for the meetings, responsiveness to data requests and questions, and the production of the IRP itself. Although the Division's analysis is, in the end, critical of the IRP, the Division notes that the PacifiCorp staff members have been professional and amenable to examining many of the suggestions from outside parties, even when such suggestions seemed contradictory to previous requests. The Division also understands that it is probably nearly impossible to produce a document encompassing resource planning for six service territories that will satisfy the varied needs and requirements of every stakeholder group.

## I. Background

This docket was opened when PacifiCorp, dba Rocky Mountain Power (PacifiCorp, or the Company) in a letter dated January 17, 2007 filed with the Public Service Commission (Commission) a request to delay filing its 2006 Integrated Resource Plan (IRP) until March 31, 2007. There is no record of a Commission response to this request. In the letter the Company noted that it last filed an IRP in January 2005 and that it was required to file an IRP every 2 years with the Commission. About April 20, 2007 the Company circulated a "Draft" to interested parties for preliminary comment.[1] Finally, on May 30, 2007 PacifiCorp filed its IRP with the Commission and stakeholders in the process.[2] On June 4, 2007 the Commission issued a request for comments to be filed by July 27, 2007. Later the due date on comments was extended to August 31, 2007 based upon a request of the Committee of Consumer Services (Committee). The following comments and analysis are the Division's response to the aforementioned Commission request for comments.

In making its comments the Division will first present a listing of its detailed recommendations to the Company for future IRPs. Following that will be a summary of each of the Procedures, Standards and Guidelines ("Guidelines") and discussion of the Company's compliance with the guideline from the Division's perspective plus any recommendations the Division has for future IRPs relative to that guideline. The final "Analysis and Arguments" section will present the Division's overall conclusion along with supporting arguments for that conclusion.

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[1] Beginning with the "Draft" PacifiCorp began to refer to this IRP as the 2007 IRP. Prior to this time this IRP was known as the 2006 IRP. In its Notice of [a] Technical Conference issued April 25, 2007, the Commission refers to the 2006 Integrated Resource Plan. The Division will use the terms "IRP" and "Action Plan" to refer to the Integrated Resource Plan and Action Plan filed on or about May 30, 2007.

[2] The "Draft" included only Appendix A. The "Final" was substantially the same as the "Draft" but with the addition of Appendices B through J.

## II. Summary of Recommendations:

The Division recommends the following with regard to the IRP:

1. Non-acknowledgment of the PacifiCorp IRP and the related Action Plan for not adequately meeting Utah's Guidelines.

2. The Company should make adjustments to the current Action Plan to comply with the Commission's Standards and Guidelines, especially "4e," and provide a plan for different resource acquisition paths as required by "4f." Rather than spend additional time trying to bring the remainder of the IRP and Action Plan into compliance with the Guidelines, the Company should provide an Update to this IRP by the end of 2007. Following the provision of the Update on the current IRP, the Division recommends that the Company be allowed to move on to the 2008 IRP and Action Plan, and timely provide the 2008 IRP by the end of 2008.

The Division recommends the following with regard to the 2008 IRP and future Integrated Resource Plans:

3. PacifiCorp should discuss and, if possible, quantify all externalities that can be identified, both positive and negative, beyond the air pollutants that may be issued from its plants. Such externality issues may include societal health effects from activities associated with the Company's operations, climate change, and impacts on local and regional economies. The Division believes that these externalities are not necessarily all negative.

4. PacifiCorp should continue to examine the methodology being used to forecast loads, especially over the long term and, as more data regarding loads and growth under the summer three-tier block rate becomes available, that PacifiCorp present that information

and its effect on load forecasting to interested stakeholders in Utah. Included in this analysis should be continued efforts to measure price elasticity.

5. PacifiCorp should continue to file a load/resource balance update with regulators no less than semi-annually.

6. All supply-side and demand-side resources should be treated on a consistent and comparable basis in the next and future IRPs and IRP updates.[3]

7. State Renewable Portfolio Standards (RPS) issues should be explicitly dealt with in the next IRP.

8. The 2008 IRP and future IRPs should contain a detailed discussion of the wholesale market itself and the availability of power that the Company expects to purchase at its forward prices from the market.

9. The basis of deviations from a long-term trend in its forward price curves should be fully explained in future IRPs. For example, an important component of the current IRP is the forecast near-term decline in natural gas and electric prices before they return (more or less) to trend. The Division does not believe this forecasted decline has been fully explained.

10. In future Action Plans the Company should more specifically comply with the Commission's requirement to "describe specific actions to be taken in the first two years and outline actions anticipated in the last two years."(Standards and Guidelines 4e).

[3] Hereafter, the term "IRP" will include the IRP update when applicable.

11. Future IRPs and/or Action Plans, PacifiCorp should include a detailed decision mechanism to select among and modify different resource acquisition paths as economic circumstances change (See Standards and Guidelines 4f).

12. In future IRPs the Company should include a discussion of the effect of future acquisitions on the Company's financial health and competitive risks. This discussion might also include an outline of plans for financing the resource acquisitions. (See Standards and Guidelines 4h).

13. In future IRPs the Company should include a range of costs for different externalities. (See Standards and Guidelines 4k).

14. The Company, in light of its experience in this IRP, should rethink how it will use its computer models to derive portfolios for the next IRP and seek to explain whatever process it decides upon better than in this process. The Company should maintain consistent use of the models throughout the next IRP process.

15. The Company should support the more detailed education of the Division (and other interested parties) including allowing the "hands on" experience of providing inputs into these models and observing the outputs.

16. PacifiCorp should keep a complete record of the assumptions and inputs into its forecast models including documenting any "judgment calls" that would modify the assumptions or the outputs of the models. The Company should be prepared to justify any changes in the forecasts.

17. The Company needs to include in the document a discussion explaining and documenting the Company's confidence in the market to purchase power.

18. The Company should examine its stochastic results and consider whether the implied economic circumstances would warrant continuation of the portfolio acquisition, and in the event the answer is no, whether it is appropriate to include such extreme results in the analysis.

19. PacifiCorp should make available its latest Business Plan as it is revised or updated.

20. PacifiCorp published its report, "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" in July. The report is an important input to this and future IPRs. Therefore, the Division recommends that it be evaluated through technical conferences where the research, evaluation, and conclusions are explained and justified.

21. With respect to PURPA Fuel Diversity and referencing the discussion in Chapter 7, pp 205-209 of the IRP, Division recommends that the Company also include a chart that shows the megawatt hours and the megawatts behind the percentage numbers to provide a more complete analysis of the data. The Division also recommends that the Company provide more analysis, as described more fully below in the section on PURPA.

22. PacifiCorp should have a more explicit discussion of rate design issues in future IRPs.

## **III. Discussion of Individual Procedures, Standards and Guidelines:**

The following summarizes the procedural issues promulgated by the Commission in its Report and Order in Docket 90-2035-01 dated June 18, 1992. For each individual Procedural Issue (PI) and Standard and Guideline (SG), there is a statement, usually just a summary of each procedural issue or guideline, followed by a summary of the Company's statement of its compliance found in Appendix I. The Company's statement is headed with "PC." Following the summary of the Company's statement is the Division's comments headed by "DPU." At the end of this section is a review of the Commission's requests in its Order in the 2004 IRP Docket No. 05-2035-01.

**PROCEDUAL ISSUES**

PI. 1, 2, and 3. The Commission can issue standards and guidelines (1); information exchange is best approach (2); and prudence reviews will be done at rate cases (3).

> PC/DPU
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> The Company did exchange information throughout the IRP process. The PI 1 and 3 are not dealt with in the IRP. However, the Division notes that with the passage of UCA 54-17 (Competitive Procurement Act), prudence reviews can take place outside of a rate case.

PI. 4. IRP process will be open to the public at all stages.

> DPU
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> The Company has complied with this Procedure. It held a number of public meetings and distributed a significant amount of information and details over the course of more than a year.

PI. 5. Environmental externalities and attendant costs must be included in IRP analysis.

> PC/DPU
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> PacifiCorp provided different scenarios with cost adders only for $CO_2$. Other gases (i.e. with some mention of SOx, NOx, and Hg) were included at a single cost.[4] No mention was made of particulates. Discussion of societal costs such as possible increases in health care was not included in the IRP. The Division

[4] Appendix A, pp. 20-21.

recommends that future IRPs include a discussion, and where possible quantification, of identifiable externalities in order to more fully comply with this procedural issue. There has been increased public awareness of potential societal costs related to health, but other externalities should be dealt with as well. The Division recognizes that externalities may be positive as well as negative and encourages the Company to discuss both positive and negative impacts as appropriate.

PI. 6. IRP must evaluate supply-side and demand-side resources on a consistent and comparable basis.

PC/DPU

PacifiCorp acknowledges that its treatment of Class 2 DSM was not consistent and comparable with the treatment of other supply-side and demand-side resources. Wind resources were used as a proxy for all renewable resources. The Company indicates that it intends to make corrections in future IRPs.[5] The Division recommends that all supply-side and demand-side resources be treated on a consistent and comparable basis in the next and future IRPs.

PI. 7. Avoided cost determination should be consistent with the IRP.

DPU

In compliance with the Commission Order in Docket No. 03-035-14, the Company uses the GRID model for QF avoided costs, which is not used in the IRP. However, the Company does use the IRP resources as proxies for determining avoided costs in a GRID run. The Division believes that PacifiCorp has complied with this procedure.

[5] Chapter 5, pp. 104 and 112; Appendix I, pp. 183 and 185.

PI. 8. The IRP must meet needs of the Utah service area, but must not ignore IRP requirements of other states.

DPU

The Company developed the IRP with input from the states in its service territory. The IRP discusses state-specific issues, especially Renewable Portfolio Standards (RPS). However, the Division is concerned that the IRP and its Action Plan may not adequately reflect Utah's future needs.

PI. 9. The Company's strategic plan must be directly related to the IRP.

PC

PacifiCorp admits that "[d]ue to timing and scope differences, these two plans do not match in all respects. The 2007 IRP will be used to inform the next version of the Business Plan."[6]

DPU

The Division finds this issue problematic. The Division does not understand what Business Plan the Company is referring to in the above statement. A PowerPoint presentation provided on January 16, 2007 is titled "Business Plan Overview with Utah Stakeholders." However this "Business Plan" is certainly incomplete and does not inform the changes that occurred between January 16 and the issuance of the Draft IRP.

The determination to go with a 12 percent Planning Reserve Margin,[7] adjustments to the load forecasts, adoption of expanded use of front office transaction--all

[6] Appendix I, p. 182.
[7] The Company asserts that it is using "a reserve margin range of 12 to 15 percent" (see Appendix A, p. 1 and response to DPU data request 3.1.

without supporting analysis in the IRP--is suggestive that the IRP is being informed by some (possibly updated) “Business Plan,” and not the other way around. Perhaps this is partly the basis for the comment “[t]he modeling is intended to support rather than overshadow the expert judgment of PacifiCorp’s decision-makers.”[8] These issues are discussed further below.

**STANDARDS and GUIDELINES**

SG1. Definition of IRP… “The process should result in the selection of the optimal set of resources given the combination of costs, risk and uncertainty.”

PC

PacifiCorp suggests that the Commission has not defined “optimal.” The Company further states that “PacifiCorp believes that a successful IRP attempts to derive a robust resource plan under a reasonably wide range of potential futures.”[9]

DPU

With this definition in hand, the Company concludes that “The emphasis of the IPR is to determine the most robust resource plan under a reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future.”[10] This appears to be a clear rejection of the language of this guideline.

Because the Company appears to be using its own definition and goals for its IRP, the Division believes that PacifiCorp has not complied with this guideline. Without compliance with the Commission’s definition of an IRP, it is difficult to hold the IRP generally to be in compliance.

[8] Chapter 1, p.1.
[9] Appendix I, p. 183.
[10] Chapter 1, p.1.

SG2. The Company will submit its IRP biennially.

PC

PacifiCorp implies that it has complied with this standard and guideline because it filed for an extension (of its 2006 IRP) to March 31, 2007 with the Commission on January 17, 2007.

DPU

There is no record of the Commission responding to this extension request.

The Company was about 5 months late from a presumed January filing. PacifiCorp distributed its Draft IRP to Parties about April 20, 2007. Given the change in ownership and the need for the new management to review the Company's operations and plans, it is reasonable that the IRP would be delayed this time. However, the 2008 IRP should come out on schedule (i.e. by the end of 2008).

The Division also recommends that, whether or not the Commission decides to acknowledge the IRP and related Action Plan, PacifiCorp make adjustments to the current Action Plan to comply with the Commission's Standards and Guidelines, especially "4e," and provide a plan for different resource acquisition paths as required by "4f." After that, the Company should proceed immediately to develop its 2008 IRP instead of trying to remedy problems with this IRP. The Company should timely file its 2008 IRP by the end of 2008.

SG3. The IRP should be developed in consultation with the PSC, Division, CCS, and others and should involve the public and exchange of information.

DPU

The Company complied with this guideline. Indeed, the Division commends the Company for its efforts in providing information in general public meetings and meetings just with the Division and Utah parties.

SG4. The IRP will include the following:

ai. A range of estimates for load growth including both capacity and energy requirements. The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. Firm on system and off system loads are to be included. Non-firm loads are not to be included. Analysis of the off-system market is necessary to assess impacts of such markets on the risks associated with different acquisition strategies.

PC

PacifiCorp indicates that it implemented a load forecast range for both its deterministic models and its stochastic models. See Chapters 4 and 6 and Appendices A and E. The Company indicated that RPS issues will be modeled in subsequent IRPs.[11]

DPU

The DPU is not persuaded that the load growth analysis is adequate, particularly for capacity requirements. The IRP makes estimates of future load growth that is significantly lower than historical growth but fails to provide the detailed analysis behind the figures. Further examination of the inadequacy of the load forecast will be made later in this document.

PacifiCorp's analyses included the ability to purchase power at forward price curve costs, but there is some indication of a demand/supply imbalance beginning

[11] Appendix I, p. 183.

by 2010 in the region. The IRP contains no detailed discussion of the wholesale market itself and the availability of power that the Company expects to purchase from the market going forward. WECC's analysis regarding probable shortages in 2010 is described; however this potential shortage does not seem to be incorporated in the subsequent analyses.[12]

As an additional example of a potential problem, the price curves for both electricity and natural gas show marked declines in price over the next few years before they go up. The basis for these price curves, particularly the near-term decline in price, was not evaluated in detail. These price curves likely had a major effect on what the model will choose for resources – i.e. low market prices will tend to favor the selection of Front Office Transactions (since electricity costs are declining) and more natural gas plants (since natural gas costs are also declining). Furthermore the IRP makes estimates of future load growth that are significantly lower than historical growth but offers little detail regarding the basis for the slower growth forecast.

The Company used portfolio scenarios as a way to comply with this Guideline. As indicated above, the Division is concerned that the Company has not adequately incorporated some of the risks in its planning. The Division agrees that RPS issues need to be explicitly dealt with in the next IRP.

aii. Analyses of how various economic and demographic factors, including electricity prices and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.

[12] Chapter 3, pp. 29-30.

PC

The Company essentially claims that the information contained in Appendix A demonstrates compliance.

DPU

In developing load forecasts the Company did use many of the relevant factors mentioned in this standard. However, the Division concludes that load growth analysis is inadequate in the IRP and there is little discussion on the effects of the various factors on consumption. Therefore, the IRP does not fulfill the requirement of this guideline.

b. Evaluate supply-side and demand-side resources on a consistent and comparable basis.

PC

PacifiCorp acknowledges that its treatment of Class 2 DSM was not consistent and comparable with the treatment of other supply-side and demand-side resources (see P.6. above, and footnote 4).

DPU

As will be discussed further later on, there were limitations to the Company's evaluation of DSM resources while it awaited a new DSM study which was finished the end of June. The Company also set fixed amounts of certain resources (e.g. wind in its latest portfolios) in order to have a manageable number of variables in its computer models. The Company included some externalities explicitly in its analyses, but as suggested elsewhere the Company should expand the externalities that it evaluates in its future IRPs. While there are problems with the compliance with this Guideline, the Division does not weight these problems heavily in its decision to recommend non-acknowledgement.

bi. An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.

<u>PC</u>

The Company cites their DSM studies described in Chapter 6 and Appendix B as being compliant with this standard.

<u>DPU</u>

Some discussion of this is given in the DSM sections. However, the Company does little to discuss improvements to the Company's own current system. Presumably new plants and transmission would be at or close to state of the art and would be more efficient than the existing system.

bii. An assessment of all technically feasible generation technologies….

<u>PC</u>

PacifiCorp considered a wide range of resources in Chapters 6 and 7.

<u>DPU</u>

The Company did review and consider a wide range of technologies. The Company acknowledged that it needed to do better. PacifiCorp intends to explore new resource screening methods to accommodate a broader range of technologies while meeting the requirement to assess technologies on a "consistent and comparable basis." [13]

biii. The resource assessments should include (a number of facts about each resource).

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[13] Appendix I, p. 185.

PC

PacifiCorp captures and models these resource attributes in its IRP models.

DPU

The Company considered and discussed many of the factors mentioned at various times during the IRP process.

c. An analysis of the role of competitive bidding for demand-side and supply-side acquisitions.

PC

See Chapter 8, section on “IRP Resource Procurement Strategy.”

DPU

This is partly taken care of by UCA 54-17 and related Commission rules. In the future PacifiCorp should consider expanding the discussion on competitive bidding in light of the experience of the RFP process.

d. A 20-year planning horizon.

DPU

The Company complied with this standard.

e. A four-year action plan outlining the specific resource decisions intended to implement the IRP for the first two years and an outline of actions for the next two years in a manner consistent with the Company’s strategic business plan.

PC

Action plan is Chapter 8. A status report on the 2004 IRP Action Plan is provided as Appendix G.

DPU

The Action Plan is short on specifics for the next two years. At best, the Action Plan presents an outline covering the next four years, but actually the Action plan sketches an outline that represents activities over ten or more years. The Division concludes that the Company did not comply with this Guideline.

The reference to the Company's strategic business plan is problematic (see the Division's comments herein on PI. 9).

f. A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.

PC

The Company says that the Action Plan describes its compliance with this standard. The Company says it will use its IRP models to help inform the RFP process currently underway.

DPU

The Company has not indicated that it has a decision mechanism or plan in place to deal with changes in economic and other circumstances. The Division in its data request 3.5 asked the Company to "explain in greater detail the specific market conditions, revised load growth projects, or new regional standards that would trigger an upward revision of the PRM." The Company responded that "there are no specific triggers that signify when a revision of a target planning reserve margin is warranted. The Company looks at the totality of information available, along with stakeholder input, and then makes a determination based on its assessment of cost and risk impacts."

The Division concludes that the Company did not comply with this guideline. Failure to plan for future alternatives, or at least describe a decision mechanism for determining the Company's responses to changing situations is, in the Division's opinion, a significant shortcoming of this IRP given the potential for widely divergent results as indicated by the different scenarios and $CO_2$ levels considered in the IRP.

g. An evaluation of the cost effectiveness of the resource options from a variety of perspectives….a description of how social concerns might affect cost….

PC

The Company refers to Chapter 5 and particularly Tables 5.2-5.4 in the IRP to indicate compliance.

DPU

With the various CEM [Capacity Expansion Module] portfolios the Company constructed both on its own and in response to requests from interested parties along with its PaR [Planning and Risk module] analyses, the Company has, at least in part, complied with this guideline. The $CO_2$ adders in the different portfolio scenarios could be assumed to take into account some of the social concerns and thus complies with this Guideline. There were also discussions of other pollutants. However, the Division believes that the discussion and risk analyses of externalities needs to be expanded in future IRPs in order to fully comply with the Commission's Standards and Guidelines.[14] For example, there is recently a heightened community awareness of health issues associated with

[14] See Report and Order, Docket No. 90-2035-01, particularly the discussion on pp. 7-13.

power generation. The Division recommends that PacifiCorp expand its analysis of externalities to include as many as can reasonably be identified. See additional comments on P. 5.

h. Evaluation of financial, competitive, reliability, and operational risks in the context of the Business Plan and the IRP. Identify which risks should be borne by customers and which by stockholders.

PC

Discussions on market risks by resource type are in Chapter 5, "Resource Descriptions," and "Handling of Technology Improvement." PacifiCorp indicates that classes of risk and its allocation to customers is discussed in Chapter 2.

DPU

As indicated above the Business Plan is problematic here. The Company does provide detailed discussions of risks in Chapters 2 and 5.

i. Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent premature foreclosure of options.

PC

PacifiCorp discusses how planning flexibility came into play for the selection of the preferred portfolio (see Chapter 7 "Preferred Portfolio Selection and Justification").

DPU

The Company has asserted that increasing reliance on market purchases and reduction of the planning margin to 12 percent was done for "flexibility." What is meant by this "flexibility" is that the Company potentially avoids committing to and deploying too soon technologies that subsequently go out of favor for one reason or another. While the Division recognizes that this may be one kind of flexibility, the Company forecloses an operational flexibility by reducing its ability to respond in different ways to changing economic and operational situations. For example, not building today locks the Company into market purchases in the near and intermediate future and subjects it to the vagaries of the market. Reducing the planning reserve margin likewise reduces the Company's flexibility in its response to unscheduled plant outages or unforeseen high demand. By increasing its reliance on a reduced planning margin and increased market purchases, the Division believes the Company has not complied with this guideline.

j. An analysis of tradeoffs e.g. between reliability, dispatchability and acquisition of lowest cost resources.

PC

The Company indicates that tradeoff analysis is found in Chapter 7. A discussion of the trade-off between cost and planning reserve margin is found in Chapter 7 "Planning Reserve Margin Selection."

DPU

The Company also could argue that its CEM and PaR analyses of different portfolio options complies with this, although not explicitly. However, PacifiCorp's own analysis shows that a 15 percent planning margin is better than 12 percent but chooses to rely on 12 percent.[15] The Division believes this Guideline would require the Company to plan using the most economic risk/cost.

[15] References in the Draft that do not appear to support the 12 percent planning margin include the following: p. 7, "The portfolio modeling also showed that reducing the planning reserve margin from 15% to 12% increased $CO_2$ and other emissions due to greater reliance on the company's existing coal fleet."

k. Provide a range of external costs and analyze how these ranges of costs might affect resource acquisition.

PC

Estimated environmental externality costs for SOx, NOx, and Hg. $CO_2$ was analyzed with several different cost estimates.

DPU

Except for $CO_2$ the Company did not provide a range of external costs for other pollutants or analyze any other type of externality. As previously noted the Division recommends that the discussion and modeling of externalities be expanded in future IRPs.

l. Narrative describing how current rate design is consistent with the IRP.

PC

See Chapter 4 "Existing DSM Program Status."

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p. 148, "Alternative planning reserve margins (SAS01 and SAS02)," 1st bullet. Note that the PVRR was lowest for the 15 percent PRM base case portfolio (CAF11). This is confusing. Why isn't there more attention given to a 15 percent PRM throughout the entire planning document?
p. 202. Based on its analysis, the Company selected RA14 as the Preferred Portfolio. This Portfolio is based on a target planning reserve margin of 12%. On Page 164, second bullet, it is stated that "[l]owering the planning reserve margin increases stochastic PVRR due to the costs associated with higher Energy Not Served. Rather than reducing investment in base load plants to meet the lower load obligations, the CEM chooses to defer them."
p. 203 "…the portfolio analysis indicates that lowering the planning reserve margin increases portfolio stochastic risk and reduces reliability…"
p. 171, third bullet: "Lower the planning reserve margin from 15% to 12% (RA8) – this resource strategy raises total risk exposure; the relative increase is $11.93 for every additional PVRR dollar spent."
The lack of justification for a 12 percent PRM becomes even more puzzling in light of the footnoted reference (footnote 26 on the bottom of p. 76) recommending a 19 percent PRM for summer peak planning in the Pacific Northwest.

DPU

In Chapter 4, pages 71-74 the Company discusses various DSM programs which do affect rate design. However, the actual discussion of rate design issues is vague and unfocused. PacifiCorp should have a more explicit discussion of rate design issues in future IRPs.

SG5. PacifiCorp will submit its IRP for public comment, review and acknowledgement.

PC

Draft IRP submitted for comment on April 20, 2007 and the final on May 31, 2007.

DPU

The Company has complied with this standard.

SG6. [Interested Parties] will make formal comment to the Commission regarding the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein…If the plan needs further work, the Commission will return it with comments and suggestions for change…leading "more quickly to the Commission's acknowledgement…."

"Not addressed; this is a post-filing activity."[16]

SG7. Acknowledgement does not guarantee favorable treatment in rate cases.

"Not addressed; this is not a PacifiCorp activity."[17]

[16] Appendix I, p. 188.
[17] Ibid.

SG8. The IRP will be used in rate cases to evaluate the utility and to review avoided cost calculations.

> “Not addressed; this refers to a post-filing activity.”[18]

**ORDER in DOCKET No. 05-2035-01 (2004 IRP)**

1. Public given sufficient time for input and discussion.

PC

The Company indicates it complied and refers to Chapter 2 “Stakeholder Engagement” section.[19]

DPU

The Division agrees that the Company complied up to a point. However there were significant changes made to the Company’s assumptions between the final public meeting in April and the Draft IRP. Assumptions that were adopted without full public vetting include the five portfolios presented in the Draft and the final IRP.

These portfolios included across the board arbitrary addition of 600 MW of additional wind; they included the reliance on a 12 percent planning reserve margin, with one exception RA16. It appears that the Company was determined to select a 12 percent reserve margin no matter what the characteristics of RA16 were. The Company also adjusted its load forecast which adjustments had the

[18] Ibid.
[19] Appendix I, p. 168.

salutary effect of supporting the choice of more market purchases, rather than less.

While following the release of the Draft IRP, stakeholders were asked to respond in little more than 3 weeks. Given that there were no significant changes to the final IRP from the Draft and the (few) responses to stakeholder comments found in Appendix F, stakeholder comments on the Draft had little effect on Company thinking.

2. Biennial updates should continue.

PC/DPU

The Company agrees to do this; however, as suggested in Recommendation 2 above, the Division believes that the Company should provide an update to this IRP by the end of the year as well as produce a decision mechanism for dealing with changes in the economic and business climate, then immediately begin the process for the 2008 IRP.

3. The Company should continue to improve transparency of IRP modeling efforts to increase confidence in the results.

PC

PacifiCorp reports provided detailed modeling plan and much documentation including key portfolio analyses and information on stochastic runs.[20]

DPU

The Company's use of its models in determining the optimal portfolios seemed to change between July 2006 and the Draft IRP in April 2007. This may in part be

[20] Ibid.

due to the inexperience the Company itself has using the relatively new CEM. The Division recommends that the Company, in light of its experience in this IRP, rethink how it will use its computer models to derive portfolios for the next IRP and seek to explain whatever process it decides upon, and then seek to better explain this process than has been the case. There seems to have been a lot of confusion among various parties the Company's use of the CEM, whereby it made scenario runs followed by selecting individual resources through frequency counts, then taking these selected resources and shuffling them into new portfolios for further analysis with PaR program. This early application of the models appears to have been modified to a more straightforward use at the end of the process that was also never adequately explained.

An additional recommendation is that the Company supports the more detailed education of the Division (and other interested parties) by allowing "hands on" experience of providing inputs into these models and observing the outputs. This will likely require one or more visits to Portland by interested parties.

4 and 5. Address PURPA Fuel Sources Standard. The Company has an agreement with PSC staff to include 20-year heat rate information in the IRP.

PC

The Company indicates that it complied through the Action Plan, which includes section on Fuel Source Diversity.[21]

DPU

In 2007 the Commission issued decisions regarding the PURPA standard consideration in Docket No. 06-999-03.[22] Two of those decisions required

[21] Appendix I, p. 168.

PacifiCorp to include certain reports in its integrated resource plans; a report on the Company's plan for fossil fuel generation efficiency and generation fuel source plans.

The Commission issued its "Determination Concerning the PURPA Fossil Fuel Generation Efficiency Standard" on August 10, 2007. The order states that:

To the extent the Company has volunteered to provide this information, we hereby incorporate into the Company's IRP Standards and Guidelines the requirement for the Company to provide a 10-year Fuel Efficiency Plan in all subsequently filed biennial IRPs.

The Company proactively included a report on fossil fuel efficiency in this IRP (published before the order's release) based on commitments made in technical conferences. The Commission's order stated that it appreciated the Company including its energy efficiency plan in the current IRP, but that based on the report they "were unable to discern the Company's intent for managing fossil fuel generation efficiency."

The Commission directed that a technical conference be held to discuss the content and other details of the report. The order states:

> **In order to ensure that the Company's Fuel Efficiency Plan is apparent, provides sufficient information for evaluation, addresses the needs of the parties, and supports the goals of PURPA, we direct a technical conference be convened. The intent of this technical conference is to discuss the details associated with Plan data, location, content, implementation, results and the method(s) by which this information will be communicated to parties.**

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[22] Docket No. 06-999-03 "Consideration and Determination Respecting Certain Ratemaking Standards for Electric Utilities by the Energy Policy Act of 2005."

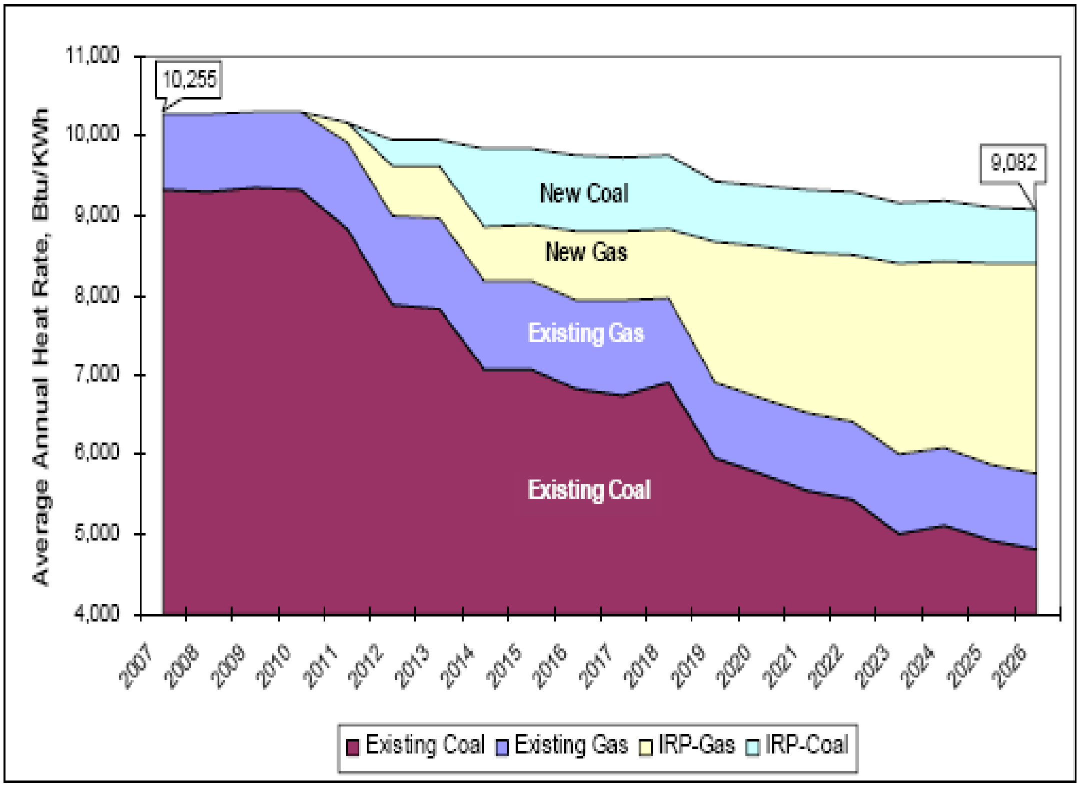
The Commission also made it clear that it expected parties to comment on the presentation of fossil fuel generation efficiency in the current IRP. The technical conference directed by the Commission will be held some time in September 2007 and comments from parties in this IRP response will be helpful to the Company to know, up front, some of the concerns of the parties. However, the Commission's order already did an excellent job of laying out the questions and concerns.

The Company reports on its energy efficiency in Chapter 7. The IRP states that "this section reports the forecasted average heat rate trend for the company's fossil fuel generator fleet on an annual basis, accounting for new IRP resources and current planned retirements of existing resources."[23] That is, it only tells us that the plan is for PacifiCorp's average heat rate for its fossil fuel generation to improve to 9,082 in 2026 from 10,255 BTU/kWh in 2007. It provides no information as to how the improvement will be made except that existing coal plants percentage contribution will decline as newer generators (including renewables) are added to the mix.

The report includes a graph that is reproduced below. Its title, "Fleet Average Fossil Fuel Head Rate Annual Trend by Generator Type" seems to indicate that it will give information as to how heat rate will improve within each category. However, that is clearly not what the graph illustrates. For example, existing coal will not improve to less than 5000 from over 9000 BTU/kWh over that time frame. Apparently what it does show is the contribution percentage of each fossil fuel type to the heat rate at a period of time.

[23] IRP, Chapter 7, p. 209.

**Figure 7.34 – Fleet Average Fossil Fuel Heat Rate Annual Trend by Generator Type**




From page 210 of the IRP

The fossil fuel efficiency report in this IRP is not what the Division hoped the Company to provide since it only gives the Company's goal without any analysis or background for how the Company intends to get to that goal. As stated in the Commission order: "Both the Division and the Committee concur any plan should be supported by a cost-benefit analysis and include environmental improvements and obligations that could affect efficiency."

The Commission issued its "Determination Concerning the PURPA Fuel Sources Standard" on March 13, 2007. The Commission determined that: "the June 18, 1992, Report and Order on Standards and Guidelines in Docket 90-2035-01 "In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp" constitutes a prior state action with respect to the PURPA Fuel Sources Standard" While the Commission determined that the prior state action had fulfilled this standard, it directed the Company to "include a section specifically addressing the PURPA Fuel Sources Standard in all future Integrated Resource Plans."

In a memo dated February 1, 2007 to the PSC, the Division recommended that the PacifiCorp include a section that details the fuel sources plan, a requirement the Company agreed to do. The Division recommended that the fuel sources plan include both fuels and technologies including technologies that manage load.

PacifiCorp included a section in the IRP titled "Fuel Diversity Planning." The section provides ways in which the company uses its planning tools to come up with a portfolio that is optimal. "PacifiCorp validated with its stochastic production cost modeling that a balanced mixture of new wind, gas, and coal resources is optimal from a cost and portfolio risk management standpoint."[24]

The Company included pie charts to illustrate how the fuel source mix changed and become more diverse from 2007 to 2016 for both energy and capacity requirements assuming the preferred portfolio implementation. The charts take into account generation and technologies including front office transactions, dispatchable DSM, Gas CHP, renewables and interruptible contracts to fulfill the recommendation to include both fuels and technologies.

The Division considers this report to be a good first effort. However in future IRP's the Division recommends that the Company also include a chart that shows the megawatt hours and the megawatts behind the percentage numbers to provide a more complete analysis of the data. The Division also recommends that the Company provide more analysis. For example, explain why Class 1 DSM

[24] IRP, p. 205.

increases such a small amount, to 1.9 percent from 1.3 percent, and why, in the capacity mix, Gas CCCTs is the only category that increases while the other categories either decrease or stay about the same on a percentage basis.

## IV. Analysis and Argument.

MODELS

This IRP is the first time the Company has used the combination of the CEM and PaR models to develop portfolios and stochastically examine portfolios, respectively. The CEM is a linear programming model that determines optimal combinations of resources and their present values given a set of assumptions and a resource stack to select from. The PaR allows selected portfolios to be analyzed by allowing certain inputs (e.g. natural gas prices) to vary randomly within a predetermined range and statistical distribution. Initially in the IRP process PacifiCorp indicated that the CEM would be used to create portfolios under a number of scenarios, and then these portfolios would be examined to determine the frequency particular resources were selected. With this resource frequency the PacifiCorp analysts would create by hand a small number of portfolios (usually five) for further analysis using PaR. Then, beginning with the analysis distributed at the October 31, 2006 public meeting the Company apparently began constructing portfolios by hand, presumably informed by the previous work, and then consecutively ran the CEM and the PaR on those hand-built portfolios. This procedure appears to have been used for the 12 portfolios developed for the February 5, 2007 public meeting (which later became the “Group 1” portfolios in the IRP), and the final 5 portfolios in the IRP (“Group 2”). The selection of final five portfolios (RA13 to RA17) included for analysis and discussion in both the Draft and the Final IRP were apparently informed by the outputs of the various runs made throughout the previous year. However, a complete explanation of how these “final five” were selected has not been made and was never vetted with public input.[25] The result is an apparently inconsistent use of these sophisticated computer programs throughout the process and has resulted in at least some confusion and, perhaps, consternation. This confusion is the basis for the Division's Recommendations 14 and 15.

The apparent inconsistent use of the computer models (assuming this is an accurate characterization) is not in and of itself a reason for recommending non-acknowledgement. The Division is concerned, however, that the "final five" portfolios were not sufficiently vetted in the public process.

## DEMAND SIDE MANAGEMENT EVALUATION

Throughout this IRP cycle, the DPU and other participants have raised questions about whether the company has evaluated demand-side resources consistently and comparably to supply-side resources.

The 2006 IRP devotes much space discussing DSM including defining each Class of DSM and gives examples of programs already in place for PacifiCorp as well as other utilities' programs that may have potential. However, much of the emphasis is on potential DSM programs that are not yet being modeled in this iteration.

Class 2 DSM (energy efficiency) projects were not specifically modeled but the plan's load forecast was adjusted downward to reflect PacifiCorp's "confidence" that Class 2 DSM could be economically acquired to reduce demand. The Company recognizes that it needs to do more analysis of all DSM, and particularly Class 2 DSM and intends to do more specific analysis. The following is from Chapter 6.

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[25] Chapter 7, pp. 179-186, discusses the selection of "Group 2" i.e. the "final five" portfolios. After discussing fixing certain resources and mentioning that the Company made some CEM runs, we are told that "Based on these results, PacifiCorp developed five portfolios…." (p. 182).

> **During the 2007 integrated resource planning process and development of the company's Class 2 energy efficiency resource assessment, there were questions raised as to whether PacifiCorp had sufficient information available, absent the completion of a system-wide demand-side resource assessment study, to arrive at a fair representation of the energy efficiency resource potential available over the planning period. While having additional data from such a study would likely have provided additional clarity around this assessment, the company had several other reliable sources of information from which to arrive at a forecast of achievable resource potential as represented within the 2007 IRP.[26]**

The Company's confidence in this information is reflected in their use for adjusting the IRP's load forecast, indicating they will be acquired within cost-effective parameters. [27]

PacifiCorp recognizes that that its analysis of DSM potential is incomplete as it awaited a new study. In July 2007, it received the study from Quantec, titled "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources." It appears that this study is a great improvement over what PacifiCorp relied on for the IRP. We expect that the Company will use the information from the study to update this IRP and to inform future IRP's to make the resource comparison more consistent and comparable. However, the study will need to be evaluated by stakeholders in the IRP process.

The Company asserts that it has met the conditions of the standard and that all resources are evaluated correctly though the Capacity Expansion Module.

> **Resources were evaluated on a consistent and comparable basis using the Capacity Expansion Module. There were some exceptions due to the availability of data for this IRP, such as Class 2 DSM.[28]**

[26] IRP, Modeling and Risk Analysis Approach, p. 137.
[27] IRP, p. 137.
[28]Appendix I, p.182.

However, we are not convinced that the models accurately reflect the cost and benefits associated with DSM resources. For example, the Capacity Expansion Module (CEM) selected fewer DSM resources selected under the "High DSM Potential" scenario than with other scenarios.

> **The CEM chose, on average, 135 megawatts of DSM resources across the alternative future studies—63 megawatts of Class 1 resources and 76 megawatts of Class 3 resources. The CEM selected Class 1 programs under all scenarios except one: the high DSM potential scenario.[29]**
>
> **The two DSM potential scenarios, CAF09 and CAF10, are intended to determine how other resource costs affect the CEM's choice of DSM resources at higher and lower levels of program participation. The High DSM potential scenario tests whether high fuel and market prices compensate for the higher DSM resource cost that accompanies greater program participation. The "low DSM potential" scenario tests the opposite set of conditions.[30]**

The CEM picks Class 1 programs under all scenarios except the high DSM potential scenario, a scenario where other resource options are higher priced (except wind resources). However, the resource cost for DSM is also higher priced so that the model does not pick Class 1 DSM.

DSM is priced higher because the cost curve for DSM is constructed in this way. The cost of DSM is estimated over the program life and discounted to estimate a per-kW levelized cost. Each type of load control program is then put into the model at the levelized price. The CEM will then fill resource requirements picking the lowest price resources first. Based on a study made by Quantec and included in the IRP as Appendix B, higher levels of DSM are assumed but the cost is also higher.

> **Note that as the market potential increases, the resource cost ($/kW/yr) for most of the DSM programs is higher as well. The**

[29] Chapter 7, p. 142.
[30] Chapter 7, p. 143.

> **higher cost reflects a greater level of incentive and administrative expenditures needed to maintain program savings at an elevated level.**[31]

Using this method, the model picks less DSM under the higher potential case and picks wind resources, which are lower cost, instead. The CEM runs are then used to construct portfolios that are subject to risk analysis to pick the preferred portfolio.

We see problems with the way the CEM is used to evaluate economic DSM resources. As the Company acknowledges, the DSM study used in the 2006 IRP was insufficient. Class 1 programs evaluated were limited and estimates made to reflect higher costs for increased levels of DSM were based on rough estimates as the Company waited for the new DSM study. Therefore, because of the lack of robust data, it is unclear what the true cost of elevated DSM levels would be.

Another problem is that under the high potential DSM scenario, all other resources are assumed to be higher cost with the exception of wind resources. According to the response to DPU data request 7.6, the Company does not model a price curve for wind resources so that wind prices remain low cost even when other resources are high.

Arguments could be made that costs would increase with greater amounts of wind as less attractive wind sites are used or transmission and interconnection costs are greater as wind sites are further away from load centers. However, the real issue is that since the model chooses the lowest cost resource and wind is in the model at the same cost when other resources costs are higher, it will pick wind. This obscures the point of the high DSM scenario which is to see what the value of various types of DSM is to the system when other resource prices are high. As the IRP states "The High DSM potential scenario tests whether high fuel and market prices compensate for the higher DSM resource cost that accompanies greater program participation."

[31] Chapter 7, p. 143.

Because lower cost wind resources remain in the resource choice, the test is obscured and doesn't provide the answer the test was looking for.

Another weakness is that the CPM screen resulted in a single DSM investment schedule developed and used in the risk analysis portfolio. Therefore, the risk reducing characteristics and how that impacts the economics of DSM is not recognized in the modeling. PacifiCorp acknowledges the weakness in this approach and states that it will attempt to correct it in the future. Footnote 45 states the following:

> **A limitation of this modeling strategy is that variable amounts of DSM and CHP resources were not subjected to risk analysis using the PaR model. PacifiCorp will continue to refine its approach to modeling distributed resources in concert with the scheduled June 2007 receipt of DSM and CHP supply curve data from the multi-state DSM potentials study.[32]**

The study, "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" referred to above is an important input to this and future IPRs. Therefore, we recommend that it be evaluated through technical conferences where the research, evaluation, and conclusions are explained and justified. The DPU believes that the IRP could greatly benefit from better information regarding demand side and other resources and think that technical conferences would assist in giving the public confidence that the study is a robust foundation for making resource decisions.

## PRICE ELASTICITY

As a follow-up to Utah's previous request for elasticity studies, the Company presents the results of three studies the Company performed.[33] The Division believes these studies have some problems. The first study uses the total residential class, the second study uses only those customers who call about their bills, and the third study uses cluster analysis wherein customers

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[32] IRP, Footnote 45, p. 128.
[33] Appendix A, pp. 12-13.

with the same usage pattern are grouped together. The three studies use different explanatory variables and functional forms, for which there is no explanation given. In the second study the sample size is only 13, which is an insufficient number for a meaningful analysis, especially when these customers are self-selecting. The first study appears to fail to consider the effect of a price change in one month will be felt in the following month, or later. The third study may be grouping together customers that may, in fact, be much different from one another. For example, customers with small energy inefficient houses may be grouped with customers with large energy efficient houses. These customers may give very different short-to-medium-term responses to changes in electric rates. Finally, much of the historical 1982 to 2005 (first study) and 1999 to the present (third study) periods were characterized by increasing real income combined with decreasing real electric prices. It strikes the Division that obtaining meaningful elasticity studies from annual data during these periods may be difficult. The Division asks that the Company continue to analyze the question of electric demand price elasticity in future IRPs.

## MEANING OF THE EXTREME RESULTS IN THE STOCHASTIC ANALYSES

The Division has some questions about the meaning of the upper-tail risk result in the stochastic analyses that have been run. (The lower tail results may perhaps have the same type of questions). What concerns the Division is whether in the real world if economic or other circumstances would really double or triple the present value cost of a portfolio from the median cost, whether those circumstances are so extreme that the portfolio would not be built. At what point (or points) in the stochastic scenarios contemplated in the current IRP do the costs represent an environment in which the economy is under severe stress? That is, when the present value of a portfolio reaches the $100 billion mark, does this not imply economic “Armageddon”? At what point would it be safe to say that, in all likelihood, PacifiCorp would stop the build-out or acquisition of the indicated resources? Does it make sense to systematically include several scenarios in the stochastic analysis wherein the Company really would not follow through with the portfolio because the implied economic conditions would be too difficult? The Division recommends that the Company examine its stochastic results and consider whether the implied economic circumstances would warrant continuation of the portfolio acquisition, and whether in the event the answer is no, whether it is appropriate to include such extreme results in the analysis.

## THE BASIS FOR NON-ACKNOWLEDGEMENT

The Division's basis for recommending that the Commission not acknowledge the IRP and Action Plan is that the Company failed to comply with key components of the Commission's Standards and Guidelines. First the Company redefined the goal of the IRP from a process that "should result in the selection of the optimal set of resources given the expected combination of costs, risks, and uncertainty"[34] to "determine the most robust resource plan under a reasonably wide range of potential futures…."[35] While the Company indicates that states have not clearly defined "optimal," the Company has not defined "robust." Whatever PacifiCorp means by "robust," it apparently does not include the following:

- reducing risk by reducing or eliminating market transactions;[36]
- accounting for the possibility that the region might be resource short as early as 2010;[37]
- preferring a 15 percent (or greater) planning reserve margin which is consistently less risky in PacifiCorp's risk analyses (and the reduction in the mean present

[34] From the definition of integrated resource planning in Docket No. 90-2035-01, Report and Order, pp. 17-18 and repeated on p. 41.
[35] Chapter 1, p. 1.
[36] Chapter 7, p. 171, First Bullet.
[37] Chapter 3, p. 29, the Company states that WECC is forecasting that "The current WECC 2006 Power Supply Assessment analyzes resource adequacy for a number of possible future conditions for sub-regions of the Western Interconnection. Under base summer conditions, this assessment indicates that three of the WECC's sub-regions (Southern California, the desert southwest and Rockies) show resource deficits by 2010. More adverse conditions accelerate the deficits for these sub-regions to 2008. These results suggest that, even for utilities or sub-regions that maintain adequate reserve margins, there is an elevated risk of periods of exposure to high and volatile market prices, and that these risks must be carefully examined in resource plans." But this apparent fact appears to be ignored in the remainder of the IRP analysis.

value for a 12 percent planning reserve margin is miniscule and certainly not significant);

- justifying the revision of its load forecasts to reduce load growth both in Utah and system-wide for the next three years;[38]
- formulating any decision mechanism for dealing with changes in circumstances from those assumed under its preferred portfolio (see discussion under Standard and Guideline 4f, above).

The Division's analysis indicates that there are weaknesses in this IRP such as its load forecast, weaknesses in evaluating all resources on a comparable basis, and choice of planning reserve margin. Because of the problems in these and other areas, the DPU does not believe that the results could be said to be optimal plan or even the most robust plan.

The Division has consistently opposed the Company move to a 12 percent planning reserve margin absent a specific study showing that such a planning reserve margin will maintain a satisfactory margin of safety and reliability for Utah ratepayers.[39] The Company has failed to provide such a study. Indeed as DPU Exhibit 1 demonstrates, PacifiCorp's own data within the IRP shows that the one "Group 2" portfolio that was based upon a 15 percent planning reserve

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[38] See Tables 4.8 and 4.9, pp. 67-68.

[39] Docket 05-035-47, DPU's "Supplemental Comments on PacifiCorp's Draft RFP," November 13, 2006, pp. 3-4: "PacifiCorp has indicated its new RFP draft includes resources needed to fulfill needs based upon a 12% planning margin. Originally, PacifiCorp proposed using a 15% planning margin which was consistent with the 2004 IRP and IRP Update. The Division believes that any change in a major IRP assumption such as the planning margin must be based upon the same type of solid analysis upon which the original assumption was based. The Company's change is not. Although it appears that the Company is going to run a scenario in the current IRP, at the request of Oregon staff, there is no solid analysis to indicate that a 12% planning margin is reasonable or will result in an appropriate or desirable level of reliability. The original assumption was based on the findings of a loss of load probability (LOLP) study completed for the 2004 IRP. This study found that while an 18% planning margin would be necessary to reach the desirable result of a 1 in 10 LOLP, a 15% planning margin would still equate to a 2 in 10 LOLP which was considered by the Division to be an acceptable level of reliability. The Division has seen no evidence, either in this proceeding or in the current IRP proceeding, to suggest that a decrease in the planning margin to 12% will still result in acceptable reliability levels for Utah customers. Indeed, at this point it is not clear what LOLP a 12% planning margin would equate to in terms of reliability levels. Given that the statute requires that a public interest finding take into consideration reliability, the Division is unwilling to advocate a proposal that does not obviously take reliability levels into account."

margin, RA16, is superior in almost every risk measure to the preferred portfolio RA14.[40] The justification that a 12 percent planning reserve margin is cheaper is based on slim evidence as Exhibit 1 also demonstrates. The slight difference shown in the mean present values of portfolio RA14 compared to RA16 is miniscule (0.1 percent or 0.001, in the carbon tax scenario, and 0.15 percent or 0.0015 for the cap and trade scenario). Given the uncertainties of the inputs to the models generating the data, these differences are certainly not "statistically significant." The Company also shows that with a 12 percent planning reserve margin it becomes resource short a year later.[41] Besides a slightly cheaper cost, the only additional rationale the Company has offered for the 12 percent planning reserve margin is so PacifiCorp can maintain "flexibility." As previously stated the Division questions the Company's interpretation of "flexibility" in this regard and believes that the Company is putting ratepayers in Utah unjustifiably at risk.

The Company altered its load forecast between the public presentation on February 1, 2007 and the final public meeting held April 18, 2007, just two days before the release of the Draft IRP. Exhibit 2 summarizes the effects of this change. In its IRP filing, PacifiCorp indicated that its IRP analysis initially used the Company's official load forecast released in May 2006 (i.e. May 2006 to February 2007) and then switched to the new official load forecast released in March 2007 (from February 2007 onward). It also indicated that what motivated this change in the load forecast was slowing growth in Utah and increased growth in Wyoming[42]. This switch resulted in slight slowing of coincident peak growth from 3.0 percent, in the load May 2006 load forecast, to 2.9 percent, in the March 2007 load forecast. Table 4.8 shows that as a result of this slow down in coincident peak growth, the coincident peak in Utah will decrease by 254 MW in 2009. Further analysis indicates that the magnitude of the deficit for the East goes down by about 30 percent for each of the first 3 years of the forecast (2007 to 2009) as we change the forecast. Also, with the change in forecast, the system as a whole begins to be in deficit in 2010 instead of 2008. These are substantial changes in the coincident peak to be attributed to a

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[40] The exception is at the 5th percentile level where RA15 appears to have better performance.
[41] See, for example, Figure 1.1, p. 4.
[42] Chapter 4, p. 60.

relatively small 0.1 percent reduction in coincident peak growth rate. Any focus on the slight change in the average annual growth rate over the next 10 years masks the much more significant near-term changes that result in the (hopefully accurate) indication of less resource needs in the coming few years. The Division is uncomfortable with this change in the load forecast which naturally is used to justify the Company's proposed resource procurement, since as discussed above, while the Company gains "flexibility" according to its definition, it loses the flexibility to respond to conditions that may be better met by having owned plant in service.

The IRP document does not explain how such a small change in growth rate could result in such large changes in the coincident peak. As mentioned above, the Company has not provided any information that justifies the change in the forecast other than to say it is based upon "judgment."[43] The impact of changing the forecast is not insignificant. Although the Division has and will continue to review PacifiCorp's load forecasts, the Division does not formally critique PacifiCorp's short-run or the long-run forecast models. The Division understands that in the world of forecasting, judgment calls about the assumptions, inputs and outputs are usually made to make the model and its results reflect the reality; however, the Division is not satisfied with the documentation of the forecast model, its assumptions, inputs, and the judgment calls, if any. Therefore, the Division recommends that the Company better document its load forecast procedure.

The Division is also not satisfied with the load forecast based upon the Company's own narrative. Discussion of the load growth estimates are found in Chapter 4 of the IRP and in Appendix A. The forecasts and analyses are made by jurisdiction and by general class and differentiate between energy and capacity requirements as required by the Utah IRP Standards and Guidelines. However, the discussion is general and provides very little information about PacifiCorp's load growth studies and how it made the final estimate based on those studies.

[43] See Response to DPU data request 3.5.

The following is from page 4 of the IRP Appendix A, providing background for the Utah growth estimates.

> **Utah continues to see natural population growth that is faster than many of the surrounding states. During the historical period, Utah experienced rapid population growth with a high rate of in-migration. However, the rate of population growth is expected to be lower in the coming decade as in-migration into the state slows. Use per customer in the residential class should continue at current levels for the forecast horizon. One of the reasons for the high usage per customer is that newer homes are assumed to be larger. In addition, it is assumed that air conditioning saturation rates for single family and manufactured houses will continue to grow.**
>
> **…**
>
> **The peak demand for the state of Utah is expected to have a high growth rate during the forecast period. This is due to several factors: first, newer residential structures are assumed to be larger; second, the air conditioning saturation rates in the state continue to increase in the residential and commercial sectors; and third, newly constructed commercial structures are assumed to be larger than during historical periods.**

The comments are general and most would support continued relatively high growth in both demand and energy. No data sources are cited to support the contention that in-migration should slow and nowhere in the analysis does PacifiCorp provide any other evidence that growth will be slowing. Despite the narrative that would appear to support continued high growth in demand, Table A.5 shows that the Company expects residential growth to slow to 3.4 percent from 4.2 percent. Most surprising is the estimate that commercial growth will slow to 3.3 percent from 5.0 percent although the narrative would appear to support upward usage growth. The following is also from page 4 of the IRP Appendix A.

> **The relatively high population growth also affects sales in the commercial sector by continued commercial customer growth. Usage per customer is projected to increase with new construction having greater square footage per building and increasing usage of office equipment. However, some of this growth is being offset from equipment efficiency gains over the forecast horizon.**

The Division believes that the Company should continue to evaluate various methods to better manage especially Utah's peak load growth. However, we believe the Company has an obligation to give specific and quantifiable grounds for its assumption that growth will have slowed from recent historical growth rates. The Commission in its 2004 IRP decision dated July 21, 2005 stated the following in its conclusions: "We direct the Company to investigate improving the transparency of the IRP modeling to increase confidence in the results." We do not think that the Company has fulfilled this direction in its load balance forecasting process.

We conclude that load growth analysis is inadequate in the IRP and therefore the IRP does not fulfill the requirement of the Guidelines that calls for "Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads."

As mentioned above, the Division continues to have fundamental concerns about the Company's intention of relying on market purchases as a significant resource. The Division considers the following quotes from the IRP:

> **The IRP and associated action plan was developed to be in strategic alignment with alignment with PacifiCorp and MidAmerican Energy Holding Company (MEHC) business principles in mind, and meets MEHC transaction commitments. The business principles that relate to long-term resource planning include (1) improving electricity system reliability, (2) investing in physical assets that bolster corporate strength and competitiveness, and (3) protecting the environment in cost-effective manner.**[44]
>
> **Eliminate market purchase after 2012 (RA2) – this resource strategy lowers total risk exposure; the relative reduction is $4.15 for every additional PVRR dollar spent.**[45]

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[44] Chapter 2, p. 14, Second Bullet.
[45] Chapter 7, p. 171, First Bullet. Emphasis removed.

In other dockets, the Company indicated that it needed to build more resources locally due to transmission constraints into Utah, particularly to the Wasatch Front.[46] Although this argument is in line with PacifiCorp's and MEHC's business priority to build more resources as stated above, the Company proposes to rely heavily on market purchases to meet future needs as is shown on Figures 7.32 and 7.33, pages 207-209. Therefore, the Company needs to include into the document an expanded discussion explaining the Company's confidence in the market to purchase power.

The Division recognizes that the IRP is an estimate and we do not expect the Company to have perfect insight and forecasts. The Utah Standards and Guidelines contain an additional guideline that we believe is relevant in this context:

"A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds."[47]

The Guidelines ask for different resource acquisition paths with a decision mechanism as economic circumstances unfold. It also expects flexibility in the process to adjust to opportunities and to prevent premature foreclosure of options. The Division in its data request 3.5 asked the Company to "explain in greater detail the specific market conditions, revised load growth projects, or new regional standards that would trigger an upward revision of the PRM [Planning Reserve Margin]." The Company responded that "there are no specific triggers that signify when a revision of a target planning reserve margin is warranted. The company looks at the totality of information available, along with stakeholder input, and then makes a determination based on its assessment of cost and risk impacts."

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[46] See Docket No. 03-035-29 (Current Creek) the direct testimony of Jon Cassity, p. 4, lines 3-12; the direct testimony of J. Rand Thurgood, p. 20, lines 9-12.
[47] Guideline 4f.

In Appendix I PacifiCorp explains how it believes it met the Guidelines in each state. Its response to the Guideline that calls for a decision mechanism the Company states that "in short, the company will use its IRP models, in conjunction with scenario analysis, to evaluate resource bids submitted under its Base Load Request For Proposals, issued on April 5, 2007."

The Division concludes that this Guideline is not met by this IRP. In particular, the response to the data request indicates that there are no formal decision mechanisms or known triggers to respond as the future unfolds. The response in Appendix I indicates that it sees that the only way it is meeting this guideline is through evaluating the RFP responses. The Company devotes considerable discussion to the great number of unknowns in both the short and long term horizon beyond the usual unknowns regarding load estimates and resource costs. We think that the Company must do a better job meeting this guideline in this time of great uncertainty.

Finally, the final portfolios considered arbitrarily include a fixed 600 MW of nameplate wind resource, as well as other arbitrary fixed resources. PacifiCorp says that previous analyses performed primarily in 2006 "informed" the selection of these portfolios; the Company also says that the fixed wind addition is a response to current events especially the recent adoption of the Washington RPS.[48] The Division understands the Company's need to consider the laws of other jurisdictions. However, the relatively sudden insertion of an additional 600 MW of wind resources certainly has an ad hoc appearance to it, as do the relatively recent determinations to accept a 12 percent planning margin and to reduce the system load forecasts. The ad hoc nature of the created portfolios *prima facie* cannot be optimal. Of the "final five" portfolios, the Company's own analysis clearly indicates that the selection of RA16 over RA14 is preferred. As discussed earlier under SG1, the Company altered the definition of IRP, wherein "optimal" was explicitly replaced with "robust." However, the Division believes that none of the final five portfolios can be shown to be the "optimal set of resources given the expected combination of costs, risk and uncertainty."

[48] Chapter 7, p. 153, also see footnote 53.

Based on the foregoing the Division cannot support the acknowledgement of PacifiCorp's IRP. The Division therefore recommends that the Commission not acknowledge PacifiCorp's Integrated Resource Plan and Action Plan.

Cc: Pete Warnken, PacifiCorp
Dave Taylor, PacifiCorp
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Nancy Kelly, Committee of Consumer Services