PacifiCorp 2008 Integrated Resource Plan

Report and Recommendations

(Errata)

Docket No. 09-2035-01

By

The Division of Public Utilities

June 18, 2009

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I. Executive Summary

The Utah Public Service Commission requested comments from interested parties on the appropriateness of PacifiCorp Draft 2008 IRP and recommendations on acknowledgement. The Commission also requested comments regarding the Company's proposed schedule for the filing of future IRPs, the redline IRP, and the wind integration study. The Utah Division of Public Utilities reviewed both the Draft 2008 IRP and a following redline version and has made a recommendation of non-acknowledgement of the 2008 IRP and the IRP Action Plan.

The Division made a number of critical findings. PacifiCorp's 2008 IRP did not sufficiently meet the following objectives requiring the Company to:

- Align its 10-year Business Plan with its 2008 IRP.
- Conduct an analysis of different planning reserve margins.
- Complete its own wind integration study using PacifiCorp wind and cost data.
- Model intermediate purchases as portfolio options that compete with other resource options and then analyze cost and risk.

The Commission criticized the use of hand-built portfolios in its 2007 IRP Order and instead asked the Company to consider its three-step approach for developing its optimal portfolio. The Division believes the 2008 IRP contains the following flaws relating to this requirement:

- The Company manually spread the wind resource quantities relatively evenly across the years from 2009-2018, instead of allowing the System Optimizer to select the timing and resource mix
- The in-service date for the CCCT for 2014 was randomly inserted
- The removal of Lake Side 2 resulted in the Company selecting Case B scenarios that were not fully vetted and were hand created based on the top performing portfolios.

- The Company created hand-built weighting adjustments for the eight performances measures but did not explain or show adequate analysis of how these weighting schemes were derived.

The Division has made a number of recommendations regarding the timing and scheduling of the IRP. Over the past few years, the IRP process has chronically been running behind schedule. For the IRP to be a useful planning tool, the Division maintains it should be simple, transparent, on schedule, and easily updated.

The Division believes that the IRP process has evolved over the 19 years since the IRP Standards and Guidelines were issued by the Utah Commission. The Division has observed a number of issues, problems, improvements, delays, and many other changes over this time period. The Division recommends that it is now time to revisit the entire IRP process. In particular, the Division believes that the IRP has become cumbersome, and in order for it to serve as a meaningful planning process, the IRP process itself needs to be formalized.

II. Background

The public process for the 2008 IRP began on February 29, 2008, when the Company held its first General Meeting for interested stakeholders. Several public meetings were held throughout the year with the various parties, which included four in-person meetings with Utah parties, as well as various conference calls and a Utah parties only stakeholder meeting on April 9, 2008. The last General Meeting for public stakeholders was held on December 18, 2008.

On February 13, 2009, the Company provided parties with a partial Draft 2008 IRP and requested informal input. After providing the parties with additional information during the week of February 23, 2009, the Company requested additional informal comments from interested parties by March 12, 2009. On March 6, 2009, the Company informed interested parties of the Company's revised 2008 IRP schedule. The revised completed Draft 2008 IRP was to be ready by March 20, 2009, with public comments due April 15, 2009, and an April 30, 2009 IRP filing with the Utah Commission. On March 11, 2009, the Company discussed this proposed schedule with interested parties.

However, the Company notified the Commission on March 19, 2009 that it would file its 2008 IRP on May 29, 2009. The Company had originally informed the Commission in June 2008 that the 2008 IRP would be filed on March 31, 2009. The Division responded with comments on March 25, 2009. On April 2, 2009 the Company provided a response and addressed comments by the Division and the Committee of Consumer Services (Committee, now Office of Consumer Services).

In an April 7, 2009 Order and Notice of Scheduling Conference, the Commission directed the Company to file its Draft IRP in Utah on April 8, 2009, which is the date the Company planned to circulate the document in other states. In addition, a Scheduling Conference on April 14, 2009 would determine a schedule and process for comments to the Commission and other issues raised by interested parties. On April 8, 2009, the Company filed its Draft IRP, as well as Appendices, with the Commission. The accompanying cover letter noted that the Draft version of the IRP was not final or complete and would be modified with additional material. In particular, the wind integration study was not included. (The April 8, 2009 Draft IRP that the Commission ordered the Company to file, is the document upon which acknowledgement or non-acknowledgement will be determined.) In addition, the Commission directed the Company to file a redline version of its complete and final 2008 IRP, its wind integration study, and its proposed schedule and rationale for the filing dates of future IRPs by May 29, 2009.[1]

On April 27, 2009, the Commission requested comments from interested parties on the appropriateness of the Draft 2008 IRP, including recommendations on acknowledgement. The Commission also requested comments regarding the Company's proposed schedule for the filing of future IRPs, the redline IRP, and the wind integration study. On May 28, 2009, the

[1] The Company's Redlined version of its 2008 IRP did not make many substantive changes from the draft.

Commission directed an Action Request to the Division and requested an explanation and statement of issues to be addressed. This Report is the Division's response to that Action Request.

III. IRP Process and Procedural Concerns

The Standards and Guidelines for Integrated Resource Planning for PacifiCorp in Utah stem from a docket opened in the year 1990. In fact, the docket name change in that case was reflective of the Commission's ongoing and broader view of the planning process. In its Order in the 1990 docket, the Commission wrote the following statement: "The process is expected to evolve over time and thus need periodic revisiting."[2] The Division believes that the process has evolved over time, and it is now time to revisit the process. We have observed problems, issues, suggestions, improvements, delays, and many other changes over the past 19 years.

The Division believes that a more formal process for information exchange, public meetings, and filing dates should be developed. (The timing and filing of the IRP is addressed in another section of this report in response to the Company's proposed filing dates.) First, throughout the IRP process from the development of the case assumptions, to the System Optimizer runs, to the continued analysis and revisions, stakeholders have been allowed to submit questions or comments to the IRP mailbox (IRP@pacificorp.com). These comments, questions, and responses are not shared with other stakeholders, but are only known to the Company. The Division recommends that all questions, informal and formal requests for information, comments, or other email be shared with all stakeholders in the process. The Commission has stated that information exchange is the most reasonable method for developing and implementing the IRP.

Second, public meetings need to be improved. Handouts and materials for stakeholder meetings need to be distributed at a minimum of one week prior to the meeting to allow parties time to formulate questions and review the material. A report should be sent to all parties after each

[2] Report and Order on Standards and Guidelines, Docket No. 90-2035-01, June 18, 1992, p. 1.

meeting that summarizes questions and provides answers from the meeting. Also, all follow-up items for information requests should be included in the meeting summary report. The Division believes that at times the meetings have been a quick flip through several PowerPoint slides with little or no time for others to comment. This has often occurred in meetings where there has been both an overloaded agenda and a lack of control over timing and questioning. (At such meetings, inordinate time is often spent on the first few agenda items, leaving only a small amount of time for concluding items.) Instead of a participative dialogue, we have witnessed more of the Company's quick review of "this is how it is." We therefore strongly urge the Company to set more realistic agendas for these meetings and to have meeting facilitators that can keep the meeting on schedule. The Division also believes that a written report of the material that will be covered in each meeting should be provided to the parties prior to the meeting as well. The PowerPoint presentation would be a summary of the report that will be presented, and stakeholders would have the full detail and material behind the topic to be covered at each meeting. Even back in the Commission's 2005 IRP Order, the Commission directed the Company "to structure the public input process to allow sufficient time for discussion of issues raised by parties and to address relevant issues raised in this IRP" and also to "investigate improving the transparency of the IRP modeling to increase confidence in the results."[3]

Third, the entire IRP cycle involves many models, not just the System Optimizer or the PaR models. For example, there is the SAE framework model by Itron used in developing the load forecast, MIDAS, the IPM, PROSYM model, Vista Decision Support System model for hydro capacity dispatch, MetrixMD model for calculating annual lost generation when relicensing hydro capacity, and others that each have a part in the IRP from planning through the selection of a preferred portfolio. The Division has concerns about the transparency of particular areas of the analytical process including the inability to validate modeling results.

[3] Report and Order, Docket No. 05-2035-01, July 21, 2005, p. 21.

Due to the timing constraints of the entire IRP process, we recommend the Company make arrangements early in the process to permit regulators and intervenors to have hands-on training, at a minimum, on the System Optimizer and PaR models and for parties to access any data or other models used by the Company in its planning process. A brief PowerPoint presentation of a model does not provide regulators with an opportunity to evaluate the model, its assumptions, or to validate the results. In August or early September the Company should schedule two full-day training sessions on separate days—one for the System Optimizer and one for the PaR model. Computers should be available so that interested parties can change assumptions and interact with the models to determine how each of them operates. This would afford parties an opportunity to ask hands-on questions that may arise. This would also help stakeholders better understand how each model operates and which assumptions are used in the models. A Company representative or someone from the Company that owns the rights to the models should be present to answer any questions, and explain all assumptions and inner workings of the models.

In order for the process to work more effectively, the Division recommends that the Company file a notice that it is beginning to work on its next IRP cycle and that a docket should be opened at that time.[4] Then all data responses, meeting reports, and other material will be filed with the Commission in this docket rather than waiting until the very end of the year-long process when the Company files its draft IRP to open a docket. Under the schedules of the past few years, there has been a time crunch to get through the analysis of the IRP itself and limited time for questions and answers before final comments are filed. The Division believes a more formal process from the beginning of the IRP process would improve the process going forward, allow better information sharing, and improve transparency of the process.

Procedural discussion. The **procedural** issues promulgated by the Commission in its Report and Order in Docket 90-2035-01 dated June 18, 1992, are stated below:

[4] Alternatively, the Commission could specify in an order the annual IRP calendar.

- The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.
- Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.
- Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings.
- PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.
- Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.
- The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.
- Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan.
- The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.
- The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.

Other than the suggestion above to improve the exchange of information, the Division believes the 2008 Draft IRP meets the Commission’s procedural requirements with the exception of one item—the business plan.

The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.

The Company has put forth several attempts to refer to the business plan throughout the 2008 IRP. The Company also prepared an Improvement Strategy Paper that it emailed to stakeholders on March 7, 2008. However, the Company admits in the 2008 IRP that two alignment strategy objectives were not met. First, the Company stated that it intended to conduct alternative portfolio development for the Business Plan with different input assumptions and run Monte Carlo production cost simulations to compare portfolio stochastic costs and risks. However, the Company ran out of time and did not conduct the analysis. Second, public reporting on the progress of the business plan preparation was not provided. In the redline version of the 2008 IRP the Company reports:

> As a consequence of the IRP modeling delay, the business plan was approved by the MEHC board of directors in December 2008—prior to the completion of IRP modeling and selection of the 2008 IRP preferred portfolio.[5]

In DPU Data Request 1.6, the Division asked the Company to provide a copy of the ten-year business plan.[6] In the Response to DPU 1.6, the Company reported that the load forecast, forward price curves, resource cost and performance attributes, and planned resources are assumptions used in the Business Plan that ***mostly*** align with the IRP. In its Response to DPU 1.7b regarding the three planning scenarios that were newly created in this IRP to supposedly align the business plan with the IRP, the Company answered with the following written statement:

> Documenting these assumptions and the changes between scenarios at a detailed level would be an onerous task. The change in scenarios comprises changes in draft internal management inputs to the 10-Year Plan and relies upon strategic information which is not used for any other purpose than determining the reasonableness of the initial forecast and desires from the operational units and assessing this against the company's strategic goals.[7]

Although the Company states that the assumptions and inputs for the IRP and business plan are consistent, the Company acknowledged in its November 12, 2008 public conference call with

[5] 2008 Integrated Resource Plan, Volume 1, May 28, 2009, Chapter 2, p. 22.
[6] The Company did not provide the business plan. The Division was able to review the Business Plan on June 15, 2009 after an incidental discovery that it was available for review at PacifiCorp's office.
[7] RMP Response to DPU Data Request 1.7b, May 14, 2009.

stakeholders that they did not develop alternative portfolios based on input assumption cases and run stochastic simulations of the alternative portfolios. The Division reviewed the Business Plan on June 15, 2009 and believes that the primary assumptions in the Business Plan mostly align with the 2008 IRP with two major exceptions. First, due to the timing delay of the filing of the 2008 Draft IRP in April, we clearly find that the modeling was not performed on time on the reference cases to meet the procedural requirement. The Division does not understand how the IRP can inform the Business Plan if the IRP analysis is conducted months after the Business Plan has been approved by MidAmerican Energy Holdings Company (MEHC's) Board of Directors. Second, the Company's inclusion of the Lake Side 2 plant was included in the Company's 2008 10-year Business Plan, but was not included in the Company's IRP. The business plan link was an issue in the previous IRP. The Commission reiterated the importance of the business plan link:

> The reason for this guideline is to ensure ratepayers receive the benefits of IRP. To the extent the Company makes business or corporate decisions affecting its view of the optimal resource plan given its expected combination of costs, risks and uncertainty, it must also provide the necessary analysis in the IRP to enable us to determine its conclusions are consistent with the public interest. This is what it means to link the two processes together.[8]

The Company has failed to meet both the 2007 Order requirement as well as its Procedural Guideline identified in the 1992 Standards and Guidelines.

As stated above, the Division believes that once the Company's 10-year Business Plan has been approved in December, the IRP team should meet in January to review the Business Plan. As the System Optimizer runs are completed in October or November, the IRP team should meet that same fall with stakeholders and discuss the results that were used to inform the Business Plan. Ideally, the Business Plan's resource acquisition plan should ***be*** the IRP.

[8] Report and Order, In the Matter of the PacifiCorp 2006 Integrated Resource Plan, Docket No. 07-2035-01, February 6, 2008, p. 33.

In order that future IRPs are not misunderstood, the Division recommends the Commission clarify, via an Order or updated Standards and Guidelines, the directional link of the Company's 10-Year Business Plan to its Integrated Resource Plan. If they are to inform each other, then they need to be developed in some manner of synchronization. In the following section on IRP timing, the Division proposes several recommendations that address alignment of the IRP and its Action Plan with the Business Plan.

IV. Comments on PacifiCorp's Paper on Timing of the IRP

In its order establishing the IRP Standards and Guidelines, Docket No. 90-2035-01, the Commission indicated that, "The Division requested that deadlines be specified for submission of the IRP, public comments and regulatory acknowledgement." The Commission, however, declined the Division's recommendation stating that "the planning process is fluid and strict adherence to deadlines might be detrimental to the quality of the submitted plan."[9]

The Division raised the issue of deadlines again in Docket No. 07-2035-01 as part of its comments on the Company's 2007 draft IRP:

> 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).[10]

Documents from Docket No. 07-2035-01 indicate that the Company asked for an extension in filing its IRP, however, there is no record of the Commission actually granting the Company's request or addressing in general the deadline issue. Therefore, the Division raised the issue again

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[9] "Report and Order on Standards and Guidelines," In the Matter of Analysis of an Integrated Resource Plan For PacifiCorp, Docket No. 90-2035-01, June 18, 1992, p. 28.

[10] Division memo, "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"), p. 11.

at the scheduling conference held on April 14, 2009, in the current docket, Docket No. 09-2035-01. Consequently, as part of the scheduling order, the Commission required the Company to file a statement of its "proposed schedule and rationale for the filing dates of future IRPs."[11] The Company filed its Paper on Timing on May 28, 2009, along with its redline version of the IRP being reviewed in this docket. The following are the Division's comments on the Company's proposed filing schedule.

Discussion

The Standards and Guidelines state, "The Company will submit its Integrated Resource Plan biennially."[12] The Company proposes meeting this standard by filing its IRP on March 31 of each odd-numbered year commencing with the next IRP. Certainly, at least superficially, the Company's proposed March 31 filing deadline would satisfy this requirement. While not necessarily opposed to a March deadline, the Division finds it incredulous that, given the Company's business plan was approved by the MEHC board the prior December, it will take an additional three months to prepare the IRP and submit it to the Commission for acknowledgement.

In its proposed IRP schedule, the PacifiCorp states, "The Company implemented an IRP and business plan alignment strategy as part of its overall IRP improvement plan for the 2008 IRP development cycle."[13] According to the Division's recollection, early in the 2008 IRP process, the Company indicated that the implementation plan contemplated that the IRP analysis would be substantially complete before December when the Company would take its business plan to MEHC's board for approval. The Company's proposed IRP schedule supports this interpretation: "The [alignment] strategy consists of an IRP work schedule coordinated with the preparation of the Company's 10-year business plan. . . . the Company uses the IRP models to

[11] "Requests for Comments and Scheduling Order," In the Matter of Acknowledgement of PacifiCorp's Integrated Resource Plan, April 27, 2009, p. 2.
[12] "Report and Order on Standards and Guidelines," Docket No. 90-2035-01, June 18, 1992, p. 34.
[13] "Proposed Schedule and Rational of Future IRP Filings," Docket No. 09-2035-01, Submitted to the Commission by PacifiCorp on May 28, 2009, p. 1.

develop resource portfolios in October and November to support resource decisions made for the final version of the business plan"[14] This process is consistent with the Division's notion that the IRP and it should inform the business plan.

However, other statements in the proposed schedule seem to imply that the causality runs in the opposite direction: "Following resource [business] plan approval in December, PacifiCorp then develops the IRP and prepares the IRP draft report for a 30-day public review period in January and February of the following year."[15] As is indicated in the proposed schedule, the Division suspects that the causality actually runs both ways:

> The IRP and business plan development schedules necessarily overlap . . . The resulting resource plan is presented to the MEHC board for review in December when the business plan is approved for all MEHC platforms. The final business plan considers financeability of individual resources and the portfolio in general, and the magnitude and timing of rate impacts . . .[16]

With this understanding in mind, if the Commission is inclined to accept a March deadline as proposed by the Company, the Division offers the following schedule recommendations. The Company should establish an IRP schedule such that, the IRP analysis, including the path analysis and the development of the preferred portfolio and Action Plan would be substantially complete by December when the Company presents its business plan to the MEHC board for approval. At the time the Company presents its business plan to the board, the Division recommends that the Company file with the Commission the draft IRP, preferred portfolio, and Action Plan. This filing would also kick off a 60-day informal comment period, with parties submitting their comments to the Company. Within 30 days of the business plan being approved, the Division recommends that the Company file a report detailing the anticipated changes to the preferred portfolio made by the MEHC board or management, and the reasons for those changes, along with the approved business plan. This will allow parties some time to

[14] Id. at p. 2.
[15] Id.
[16] Id.

include informal comments on the changes to the IRP and its Action Plan. Finally, the Division recommends that the Company file its final IRP with the Commission by March 31 of the scheduled year. In addition to the usual information, the final IRP will memorialize the changes (from the draft to the final version) in the IRP due either to the approved business plan, including any supporting analysis, or the informal comments submitted by interested parties. A formal comment period would commence with the filing of the final IRP with parties submitting their comments and recommendations on acknowledgement to the Commission. In the case where the Commission does not acknowledge the IRP, another period would commence allowing the Company to respond to the specific issues raised in the Commission's order and resubmit the IRP for final acknowledgement.

V. Standards and Guidelines

The Commission's Standards and Guidelines found in its Report and Order in Docket 90-2035-01, dated June 18, 1992, are listed below.

1. Definition:
Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.

2. The Company will submit its Integrated Resource Plan biennially.

3. IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.

4. PacifiCorp's future integrated resource plans will include:

a. A range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.

i. The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.

ii. 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.

b. An evaluation of all present and future resources, including future market opportunities (both demand-side and supply side), on a consistent and comparable basis.

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

ii An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.

iii. The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.

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

d. A 20-year planning horizon.

e. An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.

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.

g. An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.

h. An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.

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

j. An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.

k. A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.

l. A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.

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

6. The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required.

7. Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.

8. The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.

VI. Adherence with Standards and Guidelines

In this section, the Division will discuss whether the Company's 2008 IRP adheres to the Standards and Guidelines. In Volume 2, Appendix C, the Company's 2008 IRP identifies these Standards and Guidelines and addresses how and where the Company believes the IRP has addressed each respective Standard and Guideline. The Division generally will comment only on those Standards and Guidelines for which we determine the standard has not been met or for which an extended analysis was required to determine whether or not there was compliance. We will address the IRP action plan in a separate section to follow.

2. The Company will submit its Integrated Resource Plan biennially.

The Company submitted its IRP on April 8, 2009, after ordered to do so by the Commission. A redline version was filed with the Utah Commission on June 1, 2009. The Division makes these comments on this guideline to correct what was written in Appendix C of the Company's Redlined IRP on page 245. The delay in the Company's filing shortened the time period for parties to comment on the draft and redlined versions. Nevertheless, the Division still believes the Company met this requirement.

> **3. The IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.**

PacifiCorp sought public input on the early stages of the IRP input assumptions scenarios and initially developed 47 input assumptions. Public stakeholder meetings were held throughout the year and a Utah stakeholder comment meeting was held on April 9, 2008. The first general meeting was held on February 29, 2008. The next general meeting was held on May 22, 2008, followed by a general meeting on December 18, 2008. The other meetings identified in the public process portion of the IRP were conference calls or meetings with other states.[17] For a period of approximately seven months (June-December), there were no in-person general stakeholder meetings. During this time the process was not transparent and afforded limited opportunity for information exchange. The Company did not share data responses or questions from stakeholders with other parties. The Company subsequently developed another 10 portfolios without public input to account for the removal of the Lake Side 2 plant. The new cases were developed using the original top-performing portfolios. We do not know which portfolios would have resulted in the top-ten performing portfolios had the analysis been conducted consistently from the beginning without the assumptions of Lake Side included in the initial portfolio runs. Consequently, the Division concludes the Company did not adequately meet this guideline.

[17] 2008 Integrated Resource Plan, Volume I, Chapter 2, p. 22.

4f. A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.

The failure of the Company to provide anything under Guideline 4f in the 2007 IRP was one of the significant bases for the Division's recommendation of non-acknowledgement. In this IRP, the Company has attempted to remedy this shortcoming by including a discussion of "Acquisition Path Analysis" on pages 252 to 254 with a table on page 258 of the Draft IRP.

The Company's "decision mechanism" is defined as "the outcome of the business planning process, which will be informed by portfolio modeling using the IRP models and updated input assumptions."[18] The Company refers to "trigger events" resulting from regulation including federal RPS enactment, renewal, or phase out of production tax credits, and federal CO_2 regulation above or below PacifiCorp's "designed CO_2 trigger point." Finally, the Company outlines qualitatively the kinds of changes that would occur should there be significant changes in load growth and gas prices. Table 9.3 and Figure 9.29 set forth summaries of the path analysis.[19]

With the inclusion of a path analysis, the Company has improved upon the 2007 IRP. However, the "decision mechanism" remains obscure at best, with the only insight to it being that it is part of the Company's business planning cycle using IRP-related models. In addition to a more specific decision mechanism for each different circumstance that seems to be called for in Guideline 4f, the Division believes that full compliance with this Guideline would have included more specific actions. For example, the optimum base portfolio (presumably the preferred portfolio) would be based upon the Company's "most likely" future scenario. Then several optimum portfolios could be derived for significant departures from the most likely scenario. Had this decision mechanism been performed the way the Division envisioned it, there would

[18] PacifiCorp Draft 2008 IRP, p. 253.
[19] Figure 9.29 in the Draft IRP was corrected to Figure 9.1 in the final version dated May 28, 2009.

have been an alternate path mechanism when load growth declined and Lake Side 2 was taken out of the resource mix. This would have obviated the delay in the IRP filing itself.

In addition, there is no discernable path analysis related to transmission. The implication seems to be that the Company intends to build or otherwise acquire these transmission lines "come what may." If that is the case, then the Company needs to explicitly state or, alternatively, discuss how significant forecast changes affect the timing or the desirability of transmission acquisitions.

With respect to Guideline 4f, the Company has included an analysis that is clearly not what the Division envisioned. The Division believes that the path analysis is weak and could be significantly improved. We also find that the Company falls short in other areas with respect to compliance with this standard as it pertains to the decision mechanism. The Division commends the Company on implementing an acquisition path analysis. However, the decision mechanism portion of the standard needs more specificity in the path changes under different circumstances. The Division recommends the Commission not approve this standard as being fulfilled in the Company's 2008 IRP. Otherwise, a weak analysis will never result in a desirable path analysis and decision mechanism.

6. The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan.

The Division notes that this Standard has been satisfied, as we have this opportunity to make comments on the adequacy of the 2008 IRP. However, the Division is concerned with several items that we believe are deficiencies or inadequacies in the IRP plan itself. These are noted below in a separate section.

VII. Conformance with Commission's 2007 Report and Order[20]

[20] Report and Order, In the Matter of the PacifiCorp 2006 Integrated Resource Plan, Docket No. 07-2035-01, February 6, 2008.

In its Report and Order the Commission did not acknowledge the 2006 Integrated Resource Plan (later renamed to 2007 IRP) as it did not adequately adhere to the Standards and Guidelines. The Commission provided guidance from the lessons learned in the previous IRP that the Company should implement in the development of the next IRP. The Company has worked to implement the Commission's recommendations. They are summarized below with the Division's comments following each recommendation:

- **We direct the Company, in its next IRP process, to convene a public input meeting or technical workgroup session to review its approach to load forecast variation and to address the issue of load forecast error risk. This discussion must include the Committee's concerns regarding use of 30-year normal temperatures for estimating peak demand, the number of years relied upon for developing stochastic parameters, and the role of planning reserve in managing the risks of forecast error.**[21]

The Division agrees with the Company's findings in Appendix C, p. 234—the Company has complied with this requirement.

- **We direct the Company to host a public input meeting or technical workgroup to examine the reasonableness of the range of CO2 adders for evaluating carbon regulation risk and risk mitigating resource strategies**.[22]

The Company has met this requirement. PacifiCorp held a public input meeting on modeling CO_2 adders and which also addressed CO_2 regulations on June 26, 2008.

- **We direct the Company to consider the following three-step approach for developing its optimal portfolio: 1) Identify optimal portfolios for a relatively broad, and consistently applied, set of input assumptions; 2) subject all of these optimal portfolios to stochastic risk analysis and identify superior optimal portfolios with respect to the tradeoff between expected cost and risk exposure; 3) examine the cost consequences of the superior portfolios with respect to**

[21] Id at p. 13.
[22] Id.

> **uncertainty by subjecting them to evaluation under the initial set of relatively broad input assumptions. The key difference in this approach and the approach used by the Company in IRP 2007 is we omit the frequency counts and *creation of hand-built portfolios* that are difficult to associate with any specific set of input assumptions and therefore the prevailing conditions for which the portfolio is lowest cost.** [23]

The Company has met this requirement in the initial cases discussed in Chapters 6 through 8. The Company eschews the use of hand-built portfolios, creates optimal portfolios based upon fairly well-defined assumptions and submits them to stochastic risk analysis. On pages 219-222 the Company provides its compliance with step three above; although it argues that it is duplicative of the stochastic analysis.[24] A compliance problem again arises with the "B" cases wherein there is no specific step three performed and the preferred portfolio was given an ad hoc adjustment for wind procurement. On page 222 of the Company's Draft IRP, the Company, in explaining the effect of the 2012 gas resource deferral decision, writes: "Two portfolios were created." The Company's created portfolios result from fixing a combined-cycle gas plant to come online in 2014. The two portfolios that were created included a 570 MW wet-cooled CCCT at Lake Side and a 536 MW dry-cooled CCCT at the Currant Creek site. Again, the Division suggests that the Company adhere to the Commission's three-step process and avoid "hand-built" portfolios. Another issue, discussed elsewhere, is the percentage weightings appear to be ad hoc in nature and resemble, if not hand-building portfolios, then hand-selected with the potential appearance that the weightings are designed to give a particular outcome. With these comments, the Division concludes that the Company did work to comply with this Order, even if not fully meeting it in all instances.

- **We direct the Company, with public input, to develop a manageable set of potential future conditions, defined by a consistently applied set of input assumptions, and to develop**

[23] Id.
[24] The Company did not submit the selected portfolios to "alternative load growth scenarios because the portfolios were developed with the same load growth forecast. Therefore, applying alternative load forecasts would have no value for cost comparison purposes." (p. 220). Since the portfolios are composed of different resource selections, the Division does not believe it necessarily follows that these differing resource portfolios would behave the same with different load forecasts, but it remains open to further evidence on this point.

a set of optimal portfolios consistent with these sets of conditions.[25]

The Company provided results on 48 initial cases, or scenarios, apparently a "manageable" number for the Company; of these, 21 were designated "core" cases with the characteristic that they were based upon medium load growth. As discussed in other sections of the report, the Company departed from consistency in assumptions by, for example, hand-modeling wind in its "B" case assumptions that were created to account for the removal of Lake Side 2 plant from the resource mix. The Company referred to this as its gas deferral strategy. The final post-Lake Side 2 "B" cases themselves were revisions of previously constructed cases, but there was no public input. As in the 2007 IRP, there was a series of last minute changes after the public vetting process was mostly completed (the last public meeting was December 18, 2008, not counting a couple of relatively brief conference calls later) that had a significant effect on the outcome of the IRP. Up to the post-Lake Side 2 events, the Company was mostly compliant with this Order. However, given the post-Lake Side 2 events, the Division does not believe the Company, in the end complied with this directive.

- **We direct the Company to continue to study the tradeoffs in planning to different planning reserve targets in future IRPs.**[26]

The Company has not met this requirement. In DPU data request 1.9 the Division asked the Company to provide the analysis conducted with respect to the aforementioned Commission directive. The Company responded as follows:

> The Company interpreted the Commission's directions to mean the testing of at least two alternative planning reserve margins. Consequently, the Company conducted comparative analysis of 12% and 15% planning reserve margin levels.[27]

The Division recommends that the Commission request some form of analysis in the Company's justification for the planning reserve margin that it has selected in its IRP. For instance, what

[25] Id.
[26] Id at p. 16.
[27] Response to DPU Data Request 1.6, May 14, 2009.

information did the Company rely on to use a 12 percent planning reserve margin rather than a 15 percent margin? Further, what information does the Company plan to use or will it use when it decides to use an entirely different planning reserve margin? The Division recommends that such accompanying analysis be provided in future IRPs.

The Company tested three of its "core" cases (case numbers 8, 17, and 24), which originally were developed with a 12 percent planning reserve margin, and a 15 percent planning reserve margin and then compared the results. The Company apparently selected these three cases because they assumed medium load and natural gas price growth rates based upon the June 2008 forward price curve, and there was one case for each non-zero CO_2 tax level. The new 15 percent planning model scenarios were given cases numbers 41, 42, and 43, respectively.

The comparisons of the three 12 percent cases with the 15 percent cases yielded results that were similar to the 2007 IRP results. For example, the PVRR of the 15 percent cases are insignificantly higher than the comparable 12 percent cases. The risk measures are better for the PVRR cases including the Loss of Load Probability (LOLP) for the 15 percent cases, as expected. However, given the change in the costs associated with Energy Not Served (ENS) discussed further below, the dollar value of ENS reduction is significantly reduced such that the Company argues that it is not cost effective to build or purchase power reserves to increase the planning reserve margin from 12 percent to 15 percent.

Because only three cases were studied and the apparently arbitrary selection of ENS tiers and costs lacking a more complete discussion of the issue (e.g. incremental costs to customers, including non-monetary costs, for incremental increases in ENS), the Division does not at this time support the Company's conclusion on the planning reserve margin issue.

The Division does not believe this is what the Commission directed. In the 2007, IRP the Company claimed that it was planning for 12 to 15 percent planning reserve margins. Apparently the Company at some point decided that it will plan just to 12 percent and has not explained how it came to this conclusion. We believe that the Company's next IRP should explain or identify the metrics and the processes the Company will use to choose its planning reserve margin. In future IRPs, PacifiCorp should continue to study the tradeoffs in planning to different planning reserve targets and should justify its choice for using a 12 percent planning reserve margin. The Company has not met this requirement.

- **We direct the Company to address [the issue of hydro capacity accounting] in its next IRP. For example, it may be useful to conduct sensitivity analysis regarding this assumption to identify potential risks or shortcomings of [using the sustainable one-hour peak capacity method applied for the 2007 IRP].[28]**

The Company has met this requirement. However, PacifiCorp conducted only a cursory sensitivity analysis comparing the one-hour sustained peaking period to a period using the six highest load hours over three consecutive days of highest demand. PacifiCorp reported that the effect was negligible, but did not provide the analysis.[29] The Division believes the Company should provide an in-depth analysis of the Northwest Power and Conservation Council (NPCC) methodology and continue to evaluate how to implement this method in its next IRP. The Company should review the upcoming study that the Pacific Northwest Resource Adequacy Forum has procured and report the findings, as well as an overview of the Vista Decision Support System model used to calculate hydroelectric dispatch, to IRP stakeholders.

- **We direct the Company to evaluate a full spectrum of supply-side and demand-side options which have different characteristics regarding size, dispatchability, expected cost, expected risks and lead time for construction. Modeling limitations will need to be addressed.[30]**

The IRP includes a number of different supply-side options with varying characteristics. Tables 6.2 through 6.7 provide detailed information about a number of potential east side, and west side resource options, and their related capital and O&M costs, capacities, emissions profiles and estimated in-service dates. These tables discuss each of these options under various emissions cost modeling constraints. In this respect, the Division believes that the IRP generally fulfills the

[28] Id at p. 17.
[29] 2008 Integrated Resource Plan, Volume 1, Chapter 5, pp. 88-89.
[30] Id at p. 23.

Commission's order requiring the Company to explore resource characteristics such as expected cost, size, and dispatchability. However, as was discussed above, this exploration seems only to have gone as far as placement into the resource selection stack and it is unclear whether or not some resources were seriously considered.

The Division expresses concern that the IRP does not sufficiently meet the Commission's requirement that the Company should identify expected risks and lead times for construction of many of these resources--gas, coal, and wind in particular. While there is an informative discussion on the application of supercritical coal technologies and coal plant efficiency improvements as well as natural gas generation options, there appears to be little or no discussion about the expected procurement risks for developing or not developing such resources. There is no detailed description about preferred potential sites, potential development constraints, or a detailed discussion about the risks and benefits associated with procurement of these resources. The most explicit discussion of risks appears to be centered on options such as Integrated Gasification Combined Cycle (IGCC) or nuclear that reasonably cannot be deployed in the near future.

In relation to the demand side resources (DSR), the IRP included all of the technically feasible DSR measures that were identified in the "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" study completed in June 2007. The IRP included four distinct class 1 products at the state and load areas. This resulted in approximately 40 Class 1 supply curves being included in the 2008 IRP. For Class 3, the 2008 IRP included 50 distinct supply curves which represent different combinations of products, states, and load areas. Finally, the 2008 IRP included Class 2 DSM at the state, measure, and facility level. This resulted in a 12,500 distinct combinations of measures by facility and state. Since the IRP model cannot reasonably handle all of these supply curves, the Class 2 supply curves were reduced to a manageable number by combining like measures and costs of sets of measures into a bundle.

The Division commends the Company for the amount of work it did in modeling DSR. The hardwired modeling of DSR as "load decrements" in the 2007 IRP has clearly been rectified and we urge the Company to continue DSR as dynamic resources whose value varies with changes in energy and carbon costs. We are nevertheless concerned that the Company may have gone too far by including so many specific DSR measures. As we were often informed, both in meetings and in data request responses, the Company's computing capability was strained by the number of potential resources placed into the system optimizer model. As a result, the Company declined many requests for additional resource additions or alternative portfolio development. We think that more "bundling" of DSR resources with similar characteristics could preserve the needed modeling of demand resources while allowing some "headroom" for the IRP team to respond to requests for alternative resources and portfolios.

The Division looked into whether the supply side and demand side resources were considered in consistent and comparable manner. For the DSR, the IRP used the total resource cost as was required by the Commission. From this total resource cost, the avoided transmission and distribution costs were subtracted to get the total resource cost for the DSR at the input level. This puts the demand side and the supply side resources on a consistent and comparable basis.

VIII. Comments on the Action Plan

In this section the Division provides comments on the Company's Action Plan that is required under the Commission's Standards and Guideline 4e identified previously and restated as follows:

> **4e. PacifiCorp's future integrated resource plans will include: An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will**

include a status report of the specific actions contained in the previous action plan.[31]

The Company provides its Action Plan for resource acquisitions and risk management in Chapter 9 and in Chapter 10 a separate Transmission Expansion Action Plan. The separate Transmission Expansion Action Plan is new for the 2008 IRP compared to the 2007 IRP. The Transmission Expansion Action Plan is relatively simple and will be reviewed first.

PacifiCorp discusses its overall, long-term transmission expansion plans in terms of the announced Energy Gateway Transmission Project in May 2007. Energy Gateway entails eight transmission segments. The Populus to Terminal segment is scheduled to be completed in 2010; the Mona to Limber to Oquirrh and the Oquirrh to Terminal segments in 2012; two additional segments have planned 2014 completion dates; two have forecast completion dates in 2016 and 2017; and one segment, Walla Walla to McNary, is being reconsidered. The Transmission Expansion Action Plan is well laid out with each project discussed separately with maps showing segment locations and expected completion dates. The Division commends the Company on the layout and presentation of Chapter 10.

In its comments on the 2007 IRP, the Division expressed concern that the Company's Action Plan did not follow Guidelines 4e and 4f. Specifically, the Division's criticism relative to Guideline 4e was that "[t]he 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 sketches an outline that represents activities over ten or more years. The Division concludes that the Company did not comply with this Guideline."[32] PacifiCorp has followed a similar pattern in the 2008 IRP as it did in the 2007 IRP. That is, it has discussed actions in generalities covering a 10-year or longer period.

[31] Docket No. 90-2035-01, pp 42-44.
[32] Division Comments: *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"), August 31, 2007, p. 17.

However, the Company has made some effort to more fully comply with the Commission's Guideline 4e. In its Table 9.2, the Company has added in italics "Action items anticipated to extend beyond the next two years or occur after the next two years."[33] The implication is that all non-italicized actions are expected to be completed by the end of 2010. Many of the non-italicized Action Items are fairly specific, such as "Successfully add 144 MW of wind resources in 2009…."[34] While this is an improvement over the 2007 IRP, the Division would have preferred to have seen the action items for the first two years presented as "milestones" at least on an annual basis (2009 and 2010) but preferably semi-annually, or even quarterly. After describing specific actions for the first two years, Guideline 4e requires an outline of the next two years. There is no indication that the Company attempted to specifically comply with this part of the guideline; instead, the Company gives a general description of the actions to be completed or undertaken after 2010.

The third part of Guideline 4e is that the IRP will include the status of the previous IRP's action items. On page 246-249 PacifiCorp discusses the previous action items. PacifiCorp states that the majority of the action items from the previous IRP are to be superseded by a current action item. Several are said to be completed and four action items related to procurement of super-critical coal resources and natural gas plant are designated "no longer active." As far as providing a status report, the Company has met this requirement.

In conclusion, the Company in this IRP has improved its compliance with Guideline 4e. Compliance with 4e is weak, however, in that it does not include an outline of action items specifically for years three and four. The Division has made a suggestion for the improved presentation of this Guideline. The Division commends the Company on its improvement efforts. However, the Division again believes that improvements could be made especially with

[33] PacifiCorp Draft 2008 IRP. Top of Table 9.2, pp. 241-245.
[34] The Company could have specified the wind projects that it anticipates completing in 2009, since those projects should be well underway.

the inclusion of a clear outline of action items for years three and four. Therefore, the Division finds that the Company's Action Plan falls short of meeting compliance with this requirement.

IX. Discussion of IRP Analysis and Results

The Commission's procedural guideline 6 provides an opportunity for the Division to comment on the adequacy of the plan: "The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan." The Division's comments in this section focus on several aspects with respect to what we consider are deficiencies in the 2008 IRP, including the areas of geothermal availability, adversity to new technologies, wind integration costs, over-reliance on wholesale market purchases, the weighting scheme used to rank the preferred portfolios, and a few miscellaneous findings.

Geothermal Capacity. The Company understates the potential geothermal resources in its resource portfolio modeling. The Western Governor's Task Force estimated future development of commercial geothermal generation of 230 MW by the year 2015 and 620 MW by 2025 for the state of Utah alone.[35] However, the Company arbitrarily chose 100 MW as its upper bound for geothermal resource additions using 35 MW as the size for discrete geothermal projects. The preferred portfolio (5BCCT wet) includes only 35MW of geothermal generation from Blundell 3 in the year 2013. Yet, the resource options listed in Tables 6.4 through 6.7 consistently show geothermal as among the least-cost options available.

In DPU Data Request 1.32 b, the Division asked the following:

> Given that the geothermal resources listed in Table 6.4 through 6.7 are the lowest cost resources among all west-side resources and among the lowest among east-side resources at CO_2=\$8 (lowest at CO_2=\$45), is the Company currently pursuing the development of any greenfield geothermal projects?

[35] http://www.blm.gov/wo/st/en/prog/energy/geothermal/geothermal_nationwide/Documents/Final_PEIS.html,

The Company responded that it is not currently pursuing development of its own greenfield geothermal resources.[36]

This and related responses raise two related questions: 1) Is the preferred portfolio truly optimal (or least cost / least risk) when it contains so little of a low-cost, low-carbon resource; and 2) If the model has such resources to choose from and picks only 35 MW, is there a flaw in the model or is it somehow "hardwired" to select some resource types and not others? We note, also, that the 2007 IRP yielded a very similar outcome--geothermal was cited as a low-cost resource but minimal amounts were selected for the preferred portfolio.

The Division recommends that the Company conduct a geothermal commercial potential study for geothermal energy using both Blundell technology and other alternative geothermal technologies. The study should evaluate greenfield projects in both PacifiCorp's east and west control areas. This study should be filed with the Commission for comments as soon it has been completed. Inasmuch as the Company does not currently have an estimate of the amount of economically developed geothermal resources in the states it serves, the Division recommends that the Company make this determination and include a description of all factors mentioned in the previously referred to in DPU data request 1.32e.

Adversity to New Technologies. In addition to geothermal resources, the Company tends to underestimate or undervalue other available new technologies, such as IGCC, concentrating solar, fuel cell, and nuclear. The Company appears to be technology risk adverse as it tends to weight the upfront costs heavily on such advancing technologies. In DPU data request 1.19, the Division asked for the details concerning the variables used in the System Optimizer and the weighting factors. The Company referred the Division to a PowerPoint presentation from a technical workshop in 2004. They responded as follows: (emphasis added):

> The presentation provides a ***high-level description of the model variables***. System Optimizer is not a multi-objective or goal programming system, and therefore does not include weighting factors as model inputs. Since the model is proprietary software,

[36] RMP's Response to DPU 1.32, May 21, 2009.

> additional model variable details, including user documentation, constitutes the Vendor's intellectual property. Access to such materials would require a confidentiality agreement be signed by Ventyx Energy LLC (the model vendor) and the requesting party.[37]

The modeling of assumptions used in the System Optimizer from five years ago could be outdated, but as they are unavailable for review, it is not possible to determine the validity or reliability of the model. Without knowing the assumptions of the model inputs, the results from the model outputs cannot be assessed. Being unable to assess the logic of the model, we are again left to wonder if the model is working properly or if there is some hardwiring of predetermined results in order not to select resources that the Company has otherwise decided it does not wish to pursue. If the latter, then the value of the whole IRP process is open to question.

Another curious example is the case of the fuel cell potential resource. In Tables 6.4 and 6.5 the total resource cost for the fuel cell compares quite favorably with the other resources, yet it is nowhere selected. The Division inquired about the fuel cell's non-selection in DPU data request 1.61. The Company responded basically that its costs were too high, which did not seem supported by Tables 6.4 and 6.5. A cursory Internet search by the Division raised suggestions that fuel cells may now be cost-comparable to other natural gas resources. Nevertheless, the Company included fuel cells as a potential source resource beginning in 2013 and, presumably at competitive costs. That it was not selected in any portfolio is, again, puzzling to the Division. The Division also notes that the fuel cells potentially have a positive characteristic of being able to be distributed among and within load centers, thus reducing transmission costs and, perhaps increasing general reliability. This characteristic perhaps should be modeled. In the Company's response to our data request 1.45 regarding the modeling of rooftop PV systems, the Company responded that "other renewable resources were excluded due to their small sizes."[38] Again, the Division is concerned that the Company has an apparent bias against the selection of advanced technologies.

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[37] RMP's Response to DPU data request 1.19, May 14, 2009.
[38] RMP's Response to DPU data request 1.45, May 21, 2009.

Weighting Scheme. The IRP is inadequate in its explanation and determination of importance weights for portfolio ranking. In Chapter 7 on pages 175-176, the IRP explains why the risk-adjusted PVRR is given the largest weight and why CO_2 is given the largest risk weight. However, there is no explanation of the exact weighting. For example, the risk-adjusted PVRR could be 40 percent instead of 45 percent and capital cost would be weighted higher than the 5 percent that is listed below in the depiction of Table 7.8 from the IRP. The cost measures total 70 percent and the risk measures total 30 percent. A different weighting scheme would have resulted in an entirely different preferred portfolio. The Company needs to provide analytical discussion of the exact weight percentages it used in looking at the top-performing portfolio selections, as well as why cost and risk measures are not equally weighted. At a minimum, it should present the results of a wider variety of selection criteria and weightings in order to demonstrate how portfolios perform under different valuation scenarios.

Cost Measures	Risk-adjusted PVRR	45%
	Customer rate impact	20%
	Capital cost for 2009-2018	5%
Risk Measures	CO_2 cost exposure	15%
	Production cost standard deviation	5%
	Average annual ENS	5%
	Average annual probability of ENS (July) > 25GWh	5%

Over-reliance on Wholesale Purchases. Throughout the IRP the Company implicitly and explicitly raises the issue of owning assets versus purchasing power (front office transactions). Chapter 9 has a brief section that discusses this issue. While not reaching any conclusion, the Company discusses some of the pros and cons of owning versus buying. The Division's observation here is that, whatever the risk and uncertainty of ownership are, the implicit assumption in purchasing power is that someone else is willing to assume those risks and uncertainties. If the risk and uncertainty are so onerous that PacifiCorp, with its relatively low cost of capital and its substantial financial backing, is unwilling to assume the risks of ownership, then it may be that third parties are unwilling to assume them as well. That is, perhaps no one will build generation capacity because the cost, risk, and uncertainty are too high. This is one of the concerns the Division has with respect to the Company's long-term reliance on the wholesale market. The Company appears to simply assume away this issue apparently based upon its observations of the current wholesale markets under current conditions.

The Division has been concerned for some time that the Company is putting ratepayers at risk by an over-reliance on front office transactions and other third-party purchases. The Division raised this concern in its comments on the 2007 IRP and elsewhere. For its part, the Company in this IRP states that one of its corporate goals is to reduce reliance on front office transactions and implicitly on other third party purchases. The Company implies that in this IRP it has made progress toward that goal.[39]

The Division finds this conclusion questionable. The following table accompanying this paragraph sets forth an analysis of data derived from the load and resource balance tables for the preferred portfolios in the 2007 and 2008 IRPs. As can readily be seen, both in relative and absolute terms both the front office transactions and the other purchased energy are higher in the 2008 IRP than in the 2007 IRP. The Division has difficulty seeing how this is progress towards significantly reducing reliance on front office transactions and other non-owned resources. The Company references the 2007 IRP Update portfolio (see footnote 37) which is taken directly from the business plan as indicating an improving situation with respect to reduced front office transactions in 2008 over the 2007 Update. However, the Division is uncertain of the derivation of the 2007 business plan portfolio and its relationship to the portfolios derived in the 2007 and 2008 IRPs. Further, the table below shows an increase in the reliance on front office transactions and purchased power generally, between the two biennial IRPs when load is taken into account.

[39] PacifiCorp 2008 IRP, May 28, 2009 version, p. 10. Here the Company compares the 2007 IRP Update preferred portfolio that is taken directly from the business plan, presumably approved in December 2007, and compares this portfolio with the 2008 IRP Preferred Portfolio. The fact that the FOTs in the Update are greater than for the preferred portfolio in the 2008 IRP leads the Company to state that "the 2008 preferred portfolio relies on significantly less firm market purchases for the period covered in common (2009-2017).

Therefore, the Division sees no clear evidence that the Company is moving toward satisfying its apparent goal of reducing reliance on front office transactions.

Comparison of Preferred Portfolio Front Office Transactions and Purchased Power with System Obligations Plus Reserves for 2007 and 2008 IRPs

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	2007 IRP Preferred Portfolio FOT	2007 IRP Preferred Portfolio Purchases	Total 2007 IRP Preferred Portfolio FOT and Purchases	2007 IRP System Obligation Plus Reserves Forecast	Ratio 2007 IRP FOT and Purchases to System Load Forecast	2008 IRP Preferred Portfolio FOT	2008 IRP Preferred Portfolio Purchases	Total 2008 IRP FOT and Purchases	2008 IRP System Obligation Plus Reserves Forecast	Ratio 2008 IRP FOT and Purchases to System Load Forecast	Ratio of 2008 to 2007 (Columns 11 to 6)
Year	(MW)	(MW)	(MW)	(MW)	(Percent)	(MW)	(MW)	(MW)	(MW)	(Percent)	(Percent)
2007	0	1,690	1,690	11,466	14.74%	na	na	na	na	na	na
2008	0	1,479	1,479	11,667	12.68%	na	na	na	na	na	na
2009	0	1,578	1,578	11,874	13.29%	75	2,061	2,136	12,544	17.03%	128.13%
2010	612	1,347	1,959	12,348	15.86%	50	1,749	1,799	12,793	14.06%	88.64%
2011	336	1,292	1,628	12,603	12.92%	209	1,294	1,503	12,882	11.67%	90.32%
2012	652	455	1,107	12,973	8.53%	1,233	456	1,689	13,192	12.80%	150.04%
2013	660	484	1,144	13,135	8.71%	1,332	485	1,817	13,490	13.47%	154.65%
2014	396	450	846	13,359	6.33%	939	452	1,391	13,777	10.10%	159.43%
2015	438	450	888	13,398	6.63%	941	452	1,393	13,988	9.96%	150.25%
2016	414	429	843	13,707	6.15%	917	431	1,348	14,296	9.43%	153.32%
2017	na	na	na	na	na	1,006	431	1,437	14,466	9.93%	na
2018	na	na	na	na	na	1,382	459	1,841	14,733	12.50%	na

The Company notes some benefits of reducing front office transactions. In examining the results of its core portfolios, it observes that there is a "negative correlation between risk-adjusted PVRR and the volume of front office transactions [as] is evident in Figure 8.4."[40] "Portfolios with relatively high amounts of ENS [energy not served] rely to a greater degree on front office transactions, and in the out-years, growth resources."[41] In defense of having a relatively high level of front office transactions in its preferred portfolios, the Company states, "As emphasized in PacifiCorp's 2007 IRP, PacifiCorp believes that firm market purchases benefit the preferred portfolio by increasing planning flexibility and resource diversity at a time of considerable

[40] PacifiCorp Draft 2008 IRP, p. 184.
[41] Id. at p. 200.

regulatory uncertainty. The current economic recession, coupled with the company's need for grid infrastructure and clean air investments, magnifies the importance of such flexibility for maintaining affordable customer rates. Nevertheless, PacifiCorp recognizes the risks associated with market reliance, and has in place a price hedging strategy to mitigate these risks."[42] While not disregarding the Company's points in favor of front office transactions, the Division noted in its comments on the 2007 IRP that reliance on market purchases results in inflexibility, in that over short and medium time periods, the Company locks itself into the vagaries of the market and cannot choose between market purchases and running its own plants, whichever would be most beneficial.

The Division supports the goal of reducing reliance, in particular, on front office transactions, and agrees with the Company's stated goal to reduce the same. However, the Division is still awaiting signs that this goal is being accomplished.

Wind Integration Study. The wind integration study was filed as Appendix F on June 1, 2009. Inasmuch as the Company did not complete its own wind integration costs and capacity planning study, the Company used a proxy value of $11.75/MWh based on Portland General Electric Company's (PGE) last wind study. The Division discusses below the recommendation for the Company to complete its own study. In this section we address methodological concerns and issues that should be addressed when the Company continues to complete this study.

The wind integration study identified two factors that affect wind integration costs (WIC), the inter-hour and intra-hour variability of wind generation. The former factor, inter-hour variation, has two components, namely, day-ahead and hour-ahead forecast variation. The intra-hour variation has three components: actual, "regulate down," and "regulate up" variation. Of these two factors, inter and intra-hour variation, the intra-hour variation has the largest effect on the WIC and is the only factor to vary with the CO_2 tax assumption.[43]

[42] Id. at pp. 218-219.
[43] See, PacifiCorp 2008 IRP, Volume II, Appendix F, Table F.7, p. 278.

The actual variation, an intra-hour component, as defined in the IRP is "The deviation of the actual hourly average energy from the hour-ahead forecast." The deviation, while not unbounded, is likely to be somewhat symmetrical around the forecast. That is, the actual hourly average output is just as likely to be greater or less than the hour-ahead forecast. Therefore, it may be reasonable to assume that the actual variation can be approximated using a normal distribution, which is what the IRP implicitly assumes:

> If this was the only source of intra-hour uncertainty, the quantities of reserves may be easier to estimate by taking the 97.5th percentile of the variation distribution which represents two standard deviations of forecast error . . . Reporting levels of reserves required with a 97.5% confidence interval adds n important reliability dimension to the calculation.[44]

The two (2) standard deviation rule and the associated 97.5th percentile are strongly associated with the normal distribution.[45] Interestingly, the Company carries the normality assumption over to the other two intra-hour variation components, namely, regulate down and regulate up.

Regulate down is define by the IRP as, "the difference between the maximum wind energy within the hour (using 10-minute interval wind generation data) and the energy at the beginning of the hour."[46] Again, the two standard deviation rule is applied to this component to determine the appropriate level of reserves: "Taking two standard deviations of the resultant statistical distribution allows reserves associated with this factor to be estimated at a confidence interval"[47] of 97.5%.

Symbolically, the variable regulate down can be written as

$$RD_i = M_i - w_{i1} \tag{1}$$

[44] PacifiCorp 2008 IRP, Vol. II, p. 271.
[45] Actually, for a normal distribution 1.96 standard deviations defines the 97.5th percentile; two standard deviations defines the 97.7th percentile.
[46] PacifiCorp 2008 IRP, Vol. II, p. 272.
[47] PacifiCorp 2008 IRP, Vol. II, p. 272.

where "i" is a subscript for the hour of the year (i = 1, 2, …, 8760); w_{ij} is the wind energy generation recorded at the jth 10 minute interval (j = 1, 2, …, 6); and

$$M_i = \max\{w_{i1}, w_{i2}, \ldots, w_{i6}\} \tag{2}$$

Neither of the variables on the right hand side of Equation (1) is likely to be closely approximated by a normal distribution and, thus, applying the 2-standard deviation rule to determine reserves may be misleading.

The normal distribution – the typical bell-shaped distribution – exponentially decreases, but is unbounded on either end of the distribution, and is symmetric around the mean or average of the distribution. By comparison, the recorded wind output, w_{ij}, will be truncated at zero at the lower end and at the installed capacity at the upper end. Furthermore, the distribution of w_{ij} is not likely to be centered around the mean but is likely to be right-hand skewed, a condition where the right tail is "thicker" than the left tail.

Similarly, the maximum output in any hour, M_i, is not likely to follow a normal distribution. In fact, the maximum output is an extreme statistic whose distribution, in general, is closely approximated by the Gumbel distribution, which, for the maximum is a distribution with a right-hand skew. Taking the difference between the two non-normal variables, $RD_i = M_i - w_{i1}$, therefore, is not likely to be closely approximated by a normal distribution and could lead to unacceptably large errors in estimating the necessary reserve levels.[48] The effect on the wind integration costs of erroneously applying the 2 standard deviation rule to determine the appropriate level of reserves is unknown at this time and will require further investigation. In other words, at this point, the Division is unable to determine the reliability of the Company's estimate of the wind integration costs.

[48] A similar argument can be made for the regulate up variable, which uses the minimum output, another extreme statistic, relative to the output at the beginning of the hour to help determine the appropriate level of reserves.

In addition to the statistical methodology, the Division has concerns with many other areas of PGE's analysis. First, in the Company's 2008 IRP, the wind integration costs that used the PGE proxy cost of $11.75/MWh were more than twice what the Company used in its 2007 IRP.[49]

In the 2008 IRP, the Company uses wind integration costs ranging from $9.96/MWh to $11.85/MWh, depending on the CO_2 tax level.[50] The Division's cursory analysis of other wind integration cost studies show dramatically lower costs. For example, Lawrence Berkeley National Laboratory (LBNL), examined wind generation costs in the power system, which they state depend primarily on the characteristics of wind generation, load, and generation resources in the system. Given the RPS requirements of the states in the west and current trends in wind capacity additions, LBNL finds that a wind penetration level of 10 percent or more is a reasonable assumption for the period considered during the timeframe of its analysis, which was from 2005 to 2045. At this penetration level, LBNL found that most studies show integration costs in the range of $3 to $5/MWh.[51]

The Electric Power Research Institute (EPRI) performed an analysis that addressed the costs of renewables.[52] The study included wind penetration levels, regulation, intra-hour load following, inter-hour load following, scheduling/unit commitment, and total cost of wind plant grid impacts. For PacifiCorp, using a 20 percent penetration level, EPRI reported the total wind integration costs at $5.50/MWh, close to the amount used in PacifiCorp's 2007 IRP. However, what is noteworthy is that seven out of the other eight electric utilities reported lower costs than the $5.50/MWh PacifiCorp cost. This report was presented at a conference in May 2009, and contains relatively current data.

[49] 2007 PacifiCorp IRP reports $5.10/MWh wind integration costs, Appendix J, p. 195.
[50] PacifiCorp 2008 IRP, Vol. II, p. 277.
[51] Berkeley National Laboratory, Energy Analysis Department, December, 2008. http://eetd.lbl.gov/ea/EMS/reports/lbnl-1248e.pdf.
[52] EPRI, Firming the Future: Cost (Value) of Operating Hydro to Support Other Renewables, NHA conference, May 11, 2009, presented by Thomas Key.

Another study found that total integration operating cost for up to 25 percent wind energy delivered to Minnesota customers was less than $4.50/MWh.[53]

BC Hydro conducted its independent wind integration cost assessment for its 2008 long-term acquisition plan. BC Hydro's total wind integration cost estimate found that if only regulation, load following, and unit commitment reserve costs are considered, BC Hydro's wind integration costs range from $3.80/MWh to $4.90/MWh assuming a 20 percent wind penetration level. The report notes that this value is comparable to wind integration cost estimates in other jurisdictions. However, BC Hydro noted that the costs include only inter-hour balancing costs and the cost estimate would be higher (using a balancing reserve requirement level of 2 standard deviations as discussed above).

The Division recommends that the Company consider these findings and methodological concerns along with others as it works to complete its wind integration study. The Division recommends that the Commission require the Company to complete its own wind integration cost study and file it with the Commission as soon as it is completed. Parties should have an opportunity to comment on the study and make suggestions before the costs are integrated into the next IRP. If the study is completed before the Company files it IRP Update, the Company should perform a sensitivity study with the System Optimizer capacity expansion model and the 2008 IRP preferred portfolio modeling assumptions, including the proxy value of $11.75/MWh from PGE's latest wind integration study.

<u>Energy Not Served</u>. One other consideration in this comparison is that between the 2007 and 2008 IRPs, PacifiCorp changed the way the Company calculated "energy not served" (ENS). As explained on pages 160-161 of the 2008 IRP, the Company applied a single, high cost to all ENS in previous IRPs. In 2008, it introduced tiers based upon the assumption that the longer an outage lasted, the more options the Company had to deal with it to lower the cost of the ENS event. The selection of the Company's tiers and the costs at each level are not explained and

[53] Utility Wind Integration Group, June 14-15, 2007.
http://www.ncsl.org/Portals/1/documents/energy/SCCSmithWind07.pdf.

appear arbitrary. The practical effect is to lower the benefit of strategies to reduce ENS such as increasing the planning reserve margin. The Company's basic assumption to mitigate ENS costs seems plausible, but better justification of the specifics of the reduction is warranted.

Preferred Portfolio. The Division finds that the candidates of the top performing portfolios are very similar. The analysis shows that, Case 5 outperformed Cases 8 and 9 in several areas, including capital cost, cost risk, ad LOLP. These results are before the creation of the Case B scenarios. The table below illustrates the similarity in the top performing portfolios.

Top-performing portfolios	**Portfolio Preference**	**Alternative Weighting**	**Portfolio PVRR**	**Stochastic Mean**	**PVRR[54]**
Case 5- \$45 CO_2, low Jun-08 gas price, med load growth, 12% PRM	1.0	1.2	2.4	1.0	\$40,526
Case 8 - \$45 CO_2, med Jun-08 gas price, med load growth, 12% PRM	1.1	1.0	1.6	2.0	\$41,372
Case 9 - \$45 CO_2, low Oct-08 gas price, med load growth, 12% PRM	1.3	1.5	1.9	3.0	\$40,204

When using the portfolio preference ranking, Case 5 would have been selected as the preferred portfolio. However, Case 8 scored higher in the alternative weighting scheme. When looking at the alternative weighting mechanism, stochastic mean, and PVRR, the variation between the cases is small, and the eventual outcome could have resulted in one of the other cases being selected as the preferred portfolio.

[54] Original PVRR values.

X. Recommendations to the Commission on 2008 IRP and Future IRPs

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

- We request that the Commission clarify the Standards and Guideline described above and as re-stated here: "The Company's 10-Year Business Plan must be directly related to its Integrated Resource Plan."
- The Division requests that the Company provide training to the Division and interested stakeholders on the operation and inner workings of the System Optimizer and the PaR models.
- The Company should hold an in-person, all-day General Stakeholder meeting in January of each year devoted solely to reviewing the Company's 10-year Business Plan.
- The Division requests that the Commission order or recommend that the Company continue to study reserve margins and in future IRPs to identify the analysis that the Company uses in its decision to select a planning reserve margin. For example, what information does the Company plan look at or use when it decides to use an entirely different planning reserve margin? The Division recommends that such accompanying analysis be provided in future IRPs.
- The Company should complete its own wind integration cost study and file it with the Commission as soon as it is completed. A docket should be opened at the time when the study is filed. Parties should have an opportunity to comment on the study and make suggestions before the costs are integrated into the next IRP.
- The Company should conduct a geothermal commercial potential study for geothermal energy using both Blundell technology and other alternative geothermal technologies. The study should evaluate greenfield projects in both PaciCorp's east and west control areas. This study should be filed with the Commission for comments as soon it has been

completed. Inasmuch as the Company does not currently have an estimate of the amount of economically developed geothermal resources in the states it serves, the Division recommends that the Company make this determination and include a description of all factors mentioned in the previously referred to in DPU data request 1.32 e.

- The Division recommends the Commission accept our previously stated timing and filing requirements. The Company should file the final IRP on March 31 along with the approved business plan and documentation of any changes made between the Draft and the Final IRP. Parties will be given a formal comment period to file their recommendations with the Commission.

- The Division recommends that the Commission revisit the Standards and Guidelines and evaluate the IRP process. In this regard, the Division recommends that the Commission open a docket and schedule an initial technical conference to pursue this end.

XI. Conclusion

The Division recommends non-acknowledgment of the PacifiCorp 2008 IRP and the related Action Plan for not adequately meeting Utah's Guidelines and prior Commission requirements.

The Division's analysis discovered inadequacies with the plan itself, as described above. These include, but are not limited to, the following: no analysis of planning reserve margins, the inability of the IRP to inform the Business Plan, a random weighting factor scheme performed on the top-performing portfolios, hand-built cases with the removal of the Lake Side 2 plant, advanced and emerging technologies were not considered at their full potential due to upfront cost weighting of potential resources, and lack of transparency and ability of parties to participate fully in the IRP process. Because of the problems in these and other areas, the Division cannot state that the preferred portfolio is the optimal plan or even the most robust plan. There is no direct analytical link that can lead us that conclusion. Again, the Division stresses the importance of following the Commission's three-step portfolio approach in order to avoid some of the problems that were evident in this IRP that resulted in hand-built portfolios and delays in timing of the filing of the IRP.

Inasmuch as the Division's comments have focused on the disapproving aspects of the 2008 IRP, we make note that the IRP team has worked to include more case assumptions in this IRP, has developed an improvement strategy, and has continued to put effort and resources into this flexible and evolving process. We appreciate the work of all the IRP staff that spent many hours in this endeavor.

The Division proposed an alternative time line for future IRPs, as discussed above, and made several recommendations to the Commission which we believe will improve future IRPs and the ability of future IRPs to be acknowledged in Utah. However, based on the foregoing analysis, the Division cannot support the acknowledgement of PacifiCorp's 2008 IRP. The Division therefore recommends that the Commission not acknowledge PacifiCorp's Integrated Resource Plan and Action Plan. Finally, the Division recommends that if the 2008 IRP is not acknowledged by the Commission, the Company should address the issues in the Commission's resulting Order and resubmit the IRP for final acknowledgement.