State of Utah

DEPARTMENT OF COMMERCE
Committee of Consumer Services

To: Public Service Commission

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Date: 31 March 2003

Subject: Recommendations of the Committee of Consumer Services regarding the Matter of Acknowledgement of PacifiCorp's Integrated Resource Plan 2003; Docket No. 03-2035-01

1 Background

PacifiCorp submitted its seventh Integrated Resource Plan (IRP) entitled *Integrated Resource Plan 2003* to the Public Service Commission (Commission) on 24 January 2003 as required by the 18 June 1992 Order in Docket No 90-2035-01.[1] The Commission issued a Request for Comments 31 January 2003 inviting comments and recommendations from interested parties regarding the reasonableness of PacifiCorp's filed IRP and whether the Commission should acknowledge the plan.[2] The Committee of Consumer Services (Committee) respectfully offers the following comments and recommendations for the Commission's consideration.

2 Discussion

2.1 History of PacifiCorp's Integrated Resource Planning

PacifiCorp's first integrated resource plan was issued in November 1989 in response to the planning requirements of the Washington Utilities and Transportation Commission and the Oregon Public Utilities Commission. It became known as Resource and Market Planning Program 1, or RAMPP 1. On 21 February 1990, the Utah Public Service

[1] PacifiCorp, *Integrated Resource Plan 2003*, January 2003.

[2] Utah Public Service Commission, *Request for Comments*, In the Matter of the Acknowledgment of PACIFICORP Integrated Resource Plan 2003, 31 January 2003, p. 1.

Commission established Docket No. 90-2035-01 and directed the Company to file RAMPP 1 in Utah. The Commission issued an Order in that docket, promulgating standards and guidelines for integrated resource planning in June of 1992, the same year that integrated resource planning became codified at the federal level in the Energy Policy Act.

Since 1990, PacifiCorp has filed a total of seven integrated resource plans with the Commission. While the Commission found the general approach of RAMPP 1 reasonable and acknowledged RAMPPs 2, 4, and the RAMPP 3 process, it withheld acknowledgment of the RAMPP 3 Action Plan and did not acknowledge RAMPPs 5 and 6 filed in December 1997 and June 2001, respectively, due to concerns regarding the link between the Company's IRP and the its Strategic Business Plan, and the Company's shift in strategy from providing surplus power to the market to reliance on market purchases without adequate market or risk analysis. [3]

The application of integrated resource planning after inclusion in national law was short-lived. By the mid-1990's restructuring of the electricity industry was being aggressively pursued on both state and national fronts. As a result many utilities were loath to acquire new resources for regulated customers, and PacifiCorp was no exception.[4] Integrated resource planning became more of an exercise undertaken to fulfill regulatory requirements than for actual planning purposes. Some utilities ceased long-term resource planning altogether.

In late May of 2000, market prices in the western interconnection skyrocketed and remained at unprecedented heights until June of 2001 when they suddenly fell as rapidly as they ascended. PacifiCorp entered this period vulnerable due to the unplanned outage at Hunter Unit 1 and its decisions to not build new resources and sell its portion of the capacity at Centralia. As a consequence of this exposed position, the Company's purchased power costs increased significantly. However, the Utah Commission, like other commissions, has not passed on the full cost of power purchased during this timeframe to ratepayers. It is within this context of unacknowledged past IRPs, resource deficits, dysfunctional markets, and cost disallowances that the Company began its current IRP cycle.

2.2 IRP Direction

Integrated Resource Plan 2003 breaks from past RAMPP studies in several positive ways. Most significantly, it appears to represent a renewed commitment on the part of PacifiCorp management to again acquire long-term resources to serve its regulated customers. The Company moved its IRP function from its Regulation Department to its Commercial and Trading Department at the beginning of this IRP cycle to "ensure integration with PacifiCorp's resource procurement, trading and risk management

[3] The Commission did not have an acknowledgement mechanism in place prior to its 1992 Order in Docket No. 90-2035-01 and so could not "acknowledge" RAMPP 1.

[4] Committee of Consumer Services*, PacifiCorp's Integrated Resource Plan, RAMPP-6, Docket No. 98-2035*, 21 December 2001, pp. 3-4 and Division of Public Utilities, *In the Matter of the Acknowledgement of PacifiCorp's Integrated Resource Plan (RAMPP-6), Docket No. 98-2035-05*, 21 December 2001, pp. 8-14.

functions."[5] It committed the necessary personnel and other resources to develop an innovative approach and conducted a strong public process. The result is a resource acquisition strategy that diversifies fuel, environmental, and market risk while maintaining flexibility to adapt as the direction of the industry becomes clearer. However, vestiges of past regulatory concerns with PacifiCorp's planning process remain. Specifically, management's concern for shareholder recovery may be influencing resource acquisition thereby resulting in continued exposure to the short-term market and a more costly acquisition strategy than necessary.

2.3 Public Process

While PacifiCorp has generally conducted a good public process, the public process in this particular IRP cycle was excellent. The use of communications technology significantly enhanced participation. Video conferencing to link Salt Lake City with Portland facilitated involvement by numerous interested Utah parties and allowed more than one participant from each regulatory agency to engage personally. Past public meetings were conducted in Portland at the PacifiCorp headquarters, which limited Utah participation unless parties chose to allocate travel funding. The telephone link was a second valuable addition. It provided interested parties in states other than Oregon and Utah a method of participating without travel.

The benefits of these enhancements to the public process flow in both directions. PacifiCorp received technical feedback and a better understanding of the broad range of concerns of the larger Utah community. By direct participation, Utah parties contributed to the filed IRP product and gained an understanding of its strengths and limitations. The result is a more technically sound IRP that is better understood by the public participants.

The PacifiCorp IRP Team's responsiveness to parties' concerns was unprecedented. In addition to holding regularly scheduled public meetings, the Company aided public participation through written responses to data requests, white papers, and special meetings held whenever issues of specific concern arose. For example, Utah parties had a serious concern regarding Transmission modeling. In order to address this concern, PacifiCorp held two telephone conferences as well as an in person meeting to make sure that the Committee and other interested parties had their concerns addressed. Even though there was never complete agreement on the issue, the Committee greatly appreciates the responsiveness of the Company to our concern and commends the IRP Team for its responsive approach. The Committee believes a better understanding of the issues and concerns of all involved was achieved.

2.4 PacifiCorp's IRP Process

The process by which PacifiCorp conducted the technical development of its IRP is discussed below. By explaining how PacifiCorp developed its IRP, we set the stage to discuss the strengths and the limitations of PacifiCorp's approach.

2.4.1Modeling Tools

[5] PacifiCorp, *Integrated Resource Plan 2003*, p.161.

In conducting an IRP, a series of analyses must be performed using utility planning software tools. PacifiCorp ultimately decided to use the following in-house tools for this IRP cycle:

- Henwood's PROSYM model – PROSYM is an hourly production cost modeling software tool that was used to simulate the economic dispatch and unit commitment process, which ultimately matches resources to the system energy requirements. The results of this simulation provide the utility planner with production costs, including fuel consumption costs, purchase power expenses, and sales revenues.
- Henwood's MarketSym model – MarketSym is also a production cost simulation tool, although it is somewhat less detailed than PROSYM. MarketSym was used to perform risk analysis in which a large number of production cost simulations were performed based on a variety of input assumptions that changed reflecting volatility in future market conditions. The results of this tool provided an assessment of how each portfolio would perform under different planning assumptions such as different load forecasts, fuel price forecasts, etc.
- Gerber Associates' Midas model – Midas is also a production cost simulation tool, which is capable of running an electrical system that spans a wide area. Midas was relied upon to develop external market price forecasts. Because it is less detailed than PROSYM, it was able to model, for example, the loads and resources of the entire Western Electrical Coordinating Council (WECC) and was used to predict what will happen to market prices over a future long-term planning horizon. The market prices obtained from Midas were then fed into both the MarketSym and PROSYM models as inputs that represented the prices of the market external to the PacifiCorp's system. Using this data, PROSYM and MarketSym were able to consider whether purchases from or sales to the external market could be made.

These modeling tools were only relied on for performing production cost analyses. None of these tools were relied on to automatically generate expansion plans based on a resource optimization model. Many of the public participants requested that this type of modeling capability be used. The Company, however, decided that the most expedient solution for this IRP cycle was to rely on in-house models. The Committee in particular pursued this issue and formally requested that PacifiCorp evaluate the feasibility of using optimization software.[6] While the Committee did not agree with PacifiCorp's ultimate decision, we accepted PacifiCorp's commitment to evaluate the use of an IRP tool with optimization logic in the next IRP.

2.4.2 Area Load Forecasting and Transmission Definition

PacifiCorp initially modeled 22 areas in which loads or resources are located.[7] Transmission limitations are modeled to limit the flow of power between the areas, or

[6] Committee of Consumer Services, *Comments and Recommendations of the Committee of Consumer Services Regarding IRP Modeling Issues*, 12 March 2002, pp. 2-3.

[7] *Integrated Resource Plan 2003*, figure C.2, p 224.

"bubbles". This modeling detail is important for two reasons. First by modeling all of these areas, PacifiCorp is able to consider the impacts of siting resources at different locations throughout its system. Furthermore, by modeling these areas, PacifiCorp is able to monitor transmission flows and take into consideration congestion impacts at different locations throughout its system.

For purposes of the production cost analysis, loads were forecast over a 20-year period. PacifiCorp assumed that peak demand would grow by 2.2% per year for the areas located within the eastern part of the system, while western loads were forecast to grow by 2.0% per year.[8]

2.4.3 Capacity Adequacy Assessment

Once PacifiCorp developed its load forecast, it had to assess the MWs of firm resources available to it. These included: thermal, geothermal, hydro and wind generation; firm market purchases and sales; and demand-side management options. The objective of the capacity adequacy assessment was to determine the amount of existing firm resources that could be relied upon into the future to meet PacifiCorp's coincident system peak load requirement.

In addition to the capacity adequacy assessment that relied on information concerning its existing system, PacifiCorp also conducted a thorough evaluation to develop other data assumptions that it could use for modeling purposes. Assumptions for existing generating units, existing demand-side management programs, environmental compliance costs, generating unit emissions rates, long-term firm purchases and sales characteristics, hydro unit characteristics, and wholesale markets attributes were assembled. [9]

PacifiCorp's IRP report provides a comparison of the coincident system peak load requirement versus the amount of firm system resource capability available to satisfy the peak load over the 2004 through 2014 time period. Over this time period, PacifiCorp's load will continue to grow, while its installed resources will decline. The decline is mainly due to a loss of long-term firm capacity purchase contracts that expire during the study period. PacifiCorp concluded that by 2014, it would require over 4,000 MW of resources to satisfy its peak load requirement plus a 15% reserve margin.[10]

As can be seen from the table below, PacifiCorp will be barely able to meet its peak load requirement in the first year analyzed in this report. In that year, its installed capacity will exceed its peak requirement by only 59 MW. When a 15% reserve margin is included in the analysis, PacifiCorp will be short 1,257 MW in 2004. PacifiCorp clearly has an immediate need to add new capacity. The primary purpose of the IRP is to determine the amount, type, and timing of new capacity to meet its firm load obligations.

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[8] *Integrated Resource Plan 2003,* Appendix K.

[9] *Integrated Resource Plan 2003*, Appendix C

[10] The capacity reserve margin will be discussed at greater length below.

PacifiCorp Capacity Adequacy Assessment

Year	Existing Installed Capacity (MW)	Peak Load (MW)	Peak Load + 15% reserve margin (MW)	Difference between Existing Capacity and peak load (MW)	Difference between Existing Capacity and peak load +15% reserve margin (MW)
2004	8,833	8,774	10,090	59	-1,257
2005	8,894	8,946	10,288	-52	-1,394
2006	8,893	8,849	10,176	44	-1,283
2007	8,800	9,025	10,379	-225	-1,579
2008	8,788	9,331	10,731	-543	-1,943
2009	8,335	9,157	10,531	-822	-2,196
2010	8,335	9,253	10,641	-918	-2,306
2011	8,299	9,472	10,893	-1,173	-2,594
2012	8,119	10,184	11,712	-2,065	-3,593
2013	7,820	10,321	11,869	-2,501	-4,049
2014	7,820	10,379	11,936	-2,559	-4,116

Note: Source of data was from the IRP report page 33

2.4.4 Resource Alternatives

Numerous types of generation resources were considered as potential new resource additions for the PacifiCorp system.[11] The resources were defined based on type of resource such as coal, gas, or renewable technologies and were separately identified as being an East or a West resource. In addition, two transmission alternatives were considered.

Market purchases were represented in PacifiCorp's models in two ways. First, candidate purchase contracts were evaluated against other resource alternatives. These purchase contracts included a number of different types of firm purchases, including block, call options, swaps, or tolling agreements. Assumptions were made about the cost of these products based on PacifiCorp's market experience. The second type of purchase modeled is the balancing transaction, including day-ahead or hour-ahead spot market purchases, which are assumed necessary to balance PacifiCorp's energy requirements on an hourly basis. Balancing transactions can be purchases or sales depending on whether PacifiCorp is long or short in any given hour. These types of transactions occur at the Palo Verde, California Oregon Border, or Mid-Columbia hubs.

[11] *Integrated Resource Plan 2003,* Table C.18, pp 209-212.

Three sources of Demand Side Management (DSM) resources were evaluated. Those sources consisted of programs currently operating or with detailed evaluation completed; future opportunities, which were captured as decrements to load; and the Energy Trust of Oregon goals for achievable DSM.

2.4.5 Portfolio Development

Absent automatic resource optimization logic, PacifiCorp had to manually develop the alternative resource portfolios. Once PacifiCorp had conducted a capacity adequacy assessment to determine the amount of capacity it required over its planning horizon and had identified resource alternatives that could be used to satisfy its capacity needs, PacifiCorp developed a series of resource portfolios, each containing different combinations of resources. PacifiCorp stated that, "Formulating the portfolios requires specifying the types and timing of resource additions such that anticipated loads are reliably served."[12]

To create its portfolios, PacifiCorp added capacity to meet reliability measures. PacifiCorp first conducted a dynamic analysis. It limited its short-term market purchases to no more than 5% of the hours in a year. This measure is dynamic because a production cost simulation had to be performed in order to calculate the number of hours. The Company then added capacity to meet its static reliability measure, the 15% target reserve margin, which is computed based peak load and installed capacity. PacifiCorp established the type of capacity needed on a year-by-year basis. Whenever a need for capacity arose, PacifiCorp first determined whether base load or peaking capacity should be added. Base load capacity was added in order to ensure that at least 60% of its peak load requirement was satisfied by base load resources.[13] Once the base load capacity was added, all remaining capacity requirements were satisfied using peaking units.

Finally, using a manual process, PacifiCorp built a series of 26 resource expansion plan alternatives, in which different resources were placed in the portfolios at different times.

2.5 IRP Modeling Issues

The manner in which PacifiCorp models expansion plan alternatives have a direct effect on the outcomes used. Accurate modeling is an important step toward a truly useful IRP. Although modeling was much improved over the last IRP, the Committee has several observations and recommendations to lead to further improvements in the process that will be discussed below.

2.5.1 DSM

In its IRP, PacifiCorp forecasts load growth of 2.2% on the East Side stating "…the Gap occurs only in the heavy load hours, which results in a load-shaping problem in the East."[14] During the summer, PacifiCorp has significant air conditioning load, which

[12] *Integrated Resource Plan,* p. 59.

[13] Coal and combined-cycle combustion turbine technologies were considered base load.

[14] *Integrated Resource Plan 2003*, pg 35.

causes “needle” peaks to occur. DSM is being considered to attempt to help manage the loads during those critical time periods.

PacifiCorp has operated DSM programs for many years, including lighting retrofit programs, compact fluorescent lighting programs, weatherization programs, and various forms of energy audits.[15] The most recent data available shows that PacifiCorp was able to reduce average peak demand by 16.67 MWa in 2001.[16] The cost of these DSM programs was $21.9 million, and the average cost was $1,314/kW,[17] or $150/MWh[18] on an average $/MWh basis. This is relatively expensive when compared to the cost of other resource alternatives.

While this does not account for all of the benefits that DSM programs provide, one very simplistic way to judge these DSM programs would be to assume that for them to be cost effective, they would have to be able to displace power that costs at least $150/MWh in each and every hour. Although, this is very expensive power on an annual average basis, it does not consider the other favorable benefits that can be attributed to DSM programs such as the benefit of generation capacity deferral, reduction in system losses, reductions in transmission and distribution expenses, and reductions in the cost of and exposure to environmental impacts. Furthermore, compared to PacifiCorp’s total system production costs that are in the range of $600 - $700 million, the cost of DSM is fairly small. Nevertheless, $21.9 million is still a considerable annual expense and all new DSM programs must be evaluated very carefully going forward.

Utah continues to experience increasing summer peak load growth, and the Company forecasts that Utah’s peak load growth will continue to outpace overall load growth into the future. Utilizing cost-effective DSM to curb expected growth would provide benefit to Utah ratepayers as well as the entire PacifiCorp system.

Concerning the kinds of DSM programs that PacifiCorp evaluated, PacifiCorp stated, “For the purpose of this IRP, the candidate DSM programs are limited to specific programs that provide financial support to encourage activity that will result in long-term reduced consumption or short-term curtailment.”[19] Several classes of DSM program types were identified and modeled as follows:

- Class 1 – Dispatchable load control programs such as air-conditioning load control.
- Class 2 – Non-dispatchable energy and capacity savings programs whose benefits endure over the life of the installed system such as efficient lighting programs.

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[15] A complete list of all existing DSM programs that have been implemented in any state that PacifiCorp operates in is listed in Table 2.2 of the IRP Report on page 26.

[16] Table 2.1 in the IRP Report, page 25

[17] $1,314/kW = $21.9 million / 16,670 kWa

[18] $150/MWh = $21.9 million / (16.67 MWa * 8760)

[19] *Integrated Resource Plan 2003,* p. 67.

- Class 3 – Non-dispatchable, short duration buydown programs, in which the customer is paid to curtail load over a short-term period, such as the energy exchange. This program has no long-term effects.
- Class 4 – Non-dispatchable educational programs such as public education and awareness programs that promote the use of energy efficient equipment.

Previously, it was mentioned that existing DSM programs appear to have been very expensive (2001 program cost of $150/MWh), while the programs currently under consideration appear to be more cost effective.[20] Out of 36 total programs listed in the report, only 8 are more expensive than $40/MWh and the two most expensive programs cost $181/MWh.

Given the disparity in the program costs between the existing DSM programs in the 2001 time period, and the new programs that PacifiCorp is evaluating as part of its IRP, the Committee believes that it would be useful for PacifiCorp to reconcile the differences in these costs, to foster a better understanding for all parties.

In addition to our concerns that the IRP appears to have a heavy reliance on DSM over the study period, additional analysis was conducted as part of the IRP to look at the possibility of going even further in adding DSM programs. As part of some sensitivity analyses that PacifiCorp conducted, it analyzed the possibility of installing even more cost effective DSM. In fact, PacifiCorp concluded that it might be possible to install as much as 300 MWa more of Class 2 DSM, and as much as 100 MW more of Class 1 DSM over the study period.[21]

Although it is the Committee's hope that even greater opportunities for cost-effective DSM will be found, we are concerned with PacifiCorp's plans for such a substantial reliance on DSM, particularly in the early years of the study period. If either the implementation of planned programs is delayed for any reason or the projected MW/MWh savings fail to materialize, PacifiCorp will be left with an even greater exposure to the market. Any failure to achieve the expected DSM results could put the Company at risk of having to make larger and more costly power purchases than are currently anticipated. When greater reliance on DSM is combined with the amount of planned renewable resources and contract purchases in the IRP, our concern increases. The Committee believes that concerns relating to the cost-effectiveness of DSM should prompt greater consideration of either adding a new unit earlier or planning more long-term firm capacity purchases.

2.5.2 Lack of Optimization Logic

Based on the Committee's analysis of PacifiCorp's portfolio building approach, the Committee believes that PacifiCorp did a reasonable job developing alternative resource portfolios. For purposes of the IRP, PacifiCorp essentially proposed a selection of 26 different portfolios for evaluation. However, PacifiCorp's method for building portfolios is

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[20] *Integrated Resource Plan 2003,* Table G.1, p. 308.

[21] See Table 8.2, page 146 of the IRP report for additional details.

a manual one, restricted by the fact that there are limitations as to the amount of unique combinations of alternatives that can be considered as part of the manual process and that such a process is very time consuming.[22]

The first thing that is time consuming is simply conducting analyses that lead to the placement of certain resources in certain portfolios. The second time-consuming element is then setting up the data manually in the production-costing model to evaluate the 26 different portfolios. For the utility planner each of these time-consuming steps provides the incentive for trying to minimize the number of alternative portfolios to consider. The trouble with this is that the IRP process attempts to find the least cost resource plan, as well as, one that satisfies other operating requirements such as reliability. While, it is true that PacifiCorp invested a considerable amount of time and effort deriving a series of 26 potential expansion plans, there can no assurance that PacifiCorp's set of 26 expansion plans contains the least possible cost resource plan. Many more plans would have been necessary to satisfy such a requirement.

The Committee proposed to PacifiCorp that as part of this IRP process, it should obtain a software tool that includes automatic resource optimization logic[23]. PacifiCorp recognized the importance of automatic resource optimization logic and will explore its possible use in the future.[24] The Committee recommends that the Commission require PacifiCorp to acquire and use automatic resource expansion logic as part of its next IRP.

2.5.4 Risk Analysis

In the last IRP, RAMPP-6, PacifiCorp was reprimanded for not having followed the IRP Standards and Guidelines requirement or the subsequent orders directing the Company to conduct a risk analysis as part of the IRP.[25] The guidelines state that the Company should include: "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."[26] In RAMPP-6, PacifiCorp included limited scenarios of concern to the Company, such as the risk of higher gas prices and some load lost due to deregulation. It did not address risks stemming from load growth that is higher than modeled, environmental impacts, volatility in spot market prices, hydro conditions or other important risk considerations.

PacifiCorp has rectified this deficiency in its 2003 IRP. It conducted an elaborate analysis based on risk impacts that were identified in an open forum. PacifiCorp considered risk impacts in several ways. The first was through a stochastic Monte Carlo evaluation that considered load growth, natural gas prices, spot market energy prices,

[22] *Integrated Resource Plan 2003*, p. 233

[23] *Comments and Recommendations*, 12 March 2002.

[24] Integrated Resource Plan 2003, p. 61

[25] Committee of Consumer Services, *PacifiCorp's Integrated Resource Plan, RAMPP-6, Docket No. 98-2035*, pp. 5-6.

[26] Public Service Commission, *Report and Order on Standards and Guidelines*, p. 44.

hydro generation, and forced outages of generating units.[27] PacifiCorp stated, "The risk analysis simulates the performance of a portfolio under a large number of possible futures. The risk analysis also allows conclusions to be drawn regarding each portfolio's sensitivities to assumptions about the future and assessments to be made regarding the variability of a portfolio's cost."[28]

The method by which PacifiCorp conducted this analysis was to first develop a series of portfolios containing resource alternatives that it wanted to compare against each other. Then for each and every portfolio, it made a series of 100 data changes and ran a production cost simulation for each of the 100 data changes, which were made to the assumptions listed above. MarketSym was used to conduct this analysis. It randomly varied the input data assumptions in order to develop the 100 change cases and was then used to perform the production cost analysis.[29] A Monte Carlo process built into MarketSym generated the 100 different sets of data changes that were used in the production cost runs. Based on these production cost runs, output results were obtained and analyzed to determine the volatility associated with a given portfolio.

While the overall objective of the IRP was to determine the expansion plan that provided the lowest Present Value of Revenue Requirement, it was equally important to understand which portfolio would be robust enough to still provide low costs even when conditions change. As part of the risk analysis, different statistical measures were used to compare results.

In addition, "Stress Testing" was conducted as part of Scenario Analysis using PROSYM. Different assessments about the future were defined, and the portfolios were assessed based on that single set of changes in assumptions. Stress testing is performed because certain inputs are not easily characterized with random variations that can be modeled. Changing the West loads to model the impacts of SB 1149 is an example in which the inputs cannot easily be modeled with assumptions about random variation in the data. The process of developing the portfolios and analyzing the PacifiCorp system with the proposed new expansion plan provided PacifiCorp with a considerable amount of insight into the operation of its system.

The Committee concludes that the risk analysis that PacifiCorp performed was rigorous, led to a significantly improved understanding of its system, and met the requirements established by the Commission in its IRP Standards and Guidelines.

2.5.5 Path, Financial, and Rate Analysis

[27] A stochastic process is one in which specific volatility and correlations associated with input assumptions are considered. Different input assumptions such as load growth, fuel costs, etc., are considered in the evaluation based on the potential to have different outcomes. As a result of a stochastic process, different statistical results are available such as the mean, standard deviation, etc.

[28] *Integrated Resource Plan 2003,* p. 59.

[29] PROSYM was used in analyses where specific inputs were analyzed for a single case.

Although risk analysis is much improved from the last IRP, there are still some areas that the Committee would like PacifiCorp to examine in its next IRP. The risk related areas are path, financial, and rate analysis.

Path analysis is a process by which a utility company would evaluate the impact of a major change in assumptions mid-way through the study horizon. For example, assume that 6 years into the plan some major event were to occur, such as a significant outage of coal plant due to some unforeseen condition. A further assumption is that this sort of condition might come on with little warning and therefore that no prior planning could have predicted this event. The question arises, what path would PacifiCorp follow at that point until the end of the study horizon? This sort of analysis is very useful in considering how flexible the preferred portfolio is to conditions that might change at a specific point in time. Those that have flexible plans are able to adapt more easily to disruptive changes. The Committee recommends that PacifiCorp incorporate this sort of path analysis in its future IRP processes.

Financial analysis is another area that was completely lacking in the current IRP. This is the process of evaluating the financial impacts of a new resource expansion plan on the overall financial health of the utility. As part of the IRP, PacifiCorp conducted a revenue requirement analysis in which it forecasted the costs of operating existing resources, plus the costs of building and operating new resources. In the case of incremental new resources, capital costs are evaluated using a levelized real fixed method. This means that fixed costs were levelized on a real fixed charge rate basis, and then escalated at the cost of inflation. This levelization procedure is very useful for evaluating expansion plans that have both high and low capital cost units (coal units versus combustion turbine units). However, this analysis does not consider the utility's ability to finance and construct a capital-intensive resource plan, which requires capital recovery according to normal regulatory procedures. The utility must be capable of raising the capital to finance its construction. It is highly unlikely that PacifiCorp would ever commit to embark on a costly building program, without first understanding the financial impacts. Therefore, PacifiCorp should commit to incorporating a full financial analysis as part of its next IRP.

Rate analysis is the process of analyzing the impacts of an expansion plan on the rates of different customer classes. While PacifiCorp did investigate the impacts of the different resource plans on average overall customer rates, the analysis really only scratches the surface of what should have been analyzed with regard to customer rates. PacifiCorp did not conduct a complete financial analysis that considered embedded system costs. Instead, it only considered costs associated with the addition of new resources. This limited approach fails to fully examine how different customers would be impacted by different resource additions. The Committee recommends that a full rate analysis be conducted as part of the next IRP.

2.6 PacifiCorp's IRP Results

Results reached during this IRP process can be broken into two sections, modeling and policy. Modeling results explain what numbers the process generated; Policy results explain how PacifiCorp intends to use these numbers for resource acquisition.

2.6.1Modeling Results

PacifiCorp developed a "scorecard" for each of the 26 portfolios that it evaluated. Each scorecard contained numerical results that were used to compare each of the portfolios to one another, including Present Value of Incremental Revenue Requirements, capital costs, emissions costs, market purchases and sales, capacity factors, and east/west energy transfers.[30]

After performing a considerable amount of analysis, PacifiCorp determined that the Diversified Portfolio 1 was its optimal resource plan portfolio. The following table provides the resources that were added in each year of PacifiCorp's optimal expansion plan, which includes a combination of market purchases, gas-fired peaking and combined cycle resources, wind turbine generation, demand side management, and a coal unit.

Diversified Portfolio 1

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
East	Thermal Contract			25	25	25		25	25	25	25	175
	Class 1 DSM	30	30	31								91
	Class 2 DSM	30	12	11	12	12	12	12	12	12		125
	Wind				200		200		200		120	720
	Super Peak Contract	225				-225						0
	Coal Base Load (Hunter 4)					575						575
	CCCT (Mona)									480		480
	CCCT (Gadsby Repower)						510					510
	Peaker East (Mona)										200	200
	Reserve Peakers			200							300	500
	East Market (Short Term)	500										500
West	Thermal Contract			25	25	25		25	25	25	25	175
	Class 2 DSM	5	2	2	2	2	2	2	2	2		21
	Wind			100		200		200		200		700
	Flat Contract (7x24)								200			200
	3 Year Flat Off-peak	500			-500							0
	CCCT (Albany)				570							570
	Reserve Peakers			230						230		460
	West Market (Short Term)	500										500
	Peaking Contract									100		100
A	Total Capacity Added Each Year	1,790	44	624	334	614	724	264	464	1,074	670	
B	Cumulative Total Capacity Added	1,790	1,834	2,458	2,792	3,406	4,130	4,394	4,858	5,932	6,602	
C	Firm Capacity Added Each Year	790	44	524	134	414	524	64	264	874	550	
D	Cumulative Total Capacity Added	790	834	1,358	1,492	1,906	2,430	2,494	2,758	3,632	4,182	
	Existing Capacity	8,833	8,894	8,893	8,800	8,788	8,335	8,335	8,299	8,119	7,820	
	Existing + New Resource Plan	9,623	9,728	10,251	10,292	10,694	10,765	10,829	11,057	11,751	12,002	
	Peak Demand	8,774	8,946	8,849	9,025	9,331	9,157	9,253	9,472	10,184	10,321	
	Reserve Margin	9.7%	8.7%	15.8%	14.0%	14.6%	17.6%	17.0%	16.7%	15.4%	16.3%	

Note: A - represents total capacity added, both firm and non-firm.
C - includes only firm capacity added each year. Wind resources and east and west short term market purchases are considered non-firm

[30] *Integrated Resource Plan 2003,* Appendix E.

The Committee offers the following observations and comments on this expansion plan:

1. This expansion plan is appealing in that it has a good mixture of resource types, which helps PacifiCorp to diversify its fuel usage.
2. On a firm basis, 4,182 MW of capacity is added over the period of 2004 – 2013. On a non-firm basis, over this same period, 6,602 MW of capacity is added. Both wind resources and the East and West market short-term purchases are considered non-firm.
3. Since PacifiCorp did not assign any capacity credit to wind power resources, whenever wind power was added, that capacity did not count towards satisfying the 15% reserve margin target. As a result in those years, even more capacity besides the wind capacity had to be added to satisfy the target reserve requirement. This assumption should be reevaluated in future IRP studies.
4. There is a heavy reliance on market purchases over the planning period. This includes 350 MW of thermal contracts (175 MW on both sides of the system), 225 MW of Super Peak Contracts on the East Side for the years 2004 – 2006, 1000 MW of Market purchases (500 MW on both the East and West Sides), 200 MW of Flat 7 x 24 contract on the West Side, 500 MW of 3 year flat off-peak contracts on the West Side, and a 100 MW peaking contract on the West Side.
5. PacifiCorp establishes a criteria for a 15% reserve margin target, yet does not meet the requirement in each year. In the first two years of the study period, PacifiCorp permits lower reserve margins based on the logic that it takes a minimum of three years to build a new combined cycle unit, and a minimum of 5 years to build a new coal unit. Rather than having an insufficient margin, it may be advisable for PacifiCorp to consider making more firm capacity purchases to increase its reserve margin. This assumption should be reevaluated in future IRP studies.
6. The first major resource addition that PacifiCorp commits to build is a 570 MW combined cycle unit at Albany on the West Side of the system. The second major capacity addition built is a 575 MW coal fired generating unit added at the Hunter site on the East Side of the system. The third major resource addition is a 510 MW combined cycle unit on the East Side and finally a 480 MW repower at Gadsby is performed on the East Side.
7. In addition to the base load capacity built, about 1000 MW of peaking capacity is installed between the East and West Sides of the system.
8. A considerable amount of wind, 1400 MW in all, is installed both on the East and West Sides of the system. One of the concerns expressed by many of the parties was that the wind resources should be considered for earlier installation. As it stands now, the earliest that any of those wind resources are added on the system is 2006. This assumption should be reevaluated in future IRP studies.
9. Regarding DSM, 91 MW of Class 1 and 146 MWa of Class 2 DSM are expected to be added to the system over the study period. This is a considerable amount of DSM to rely upon. Over the last 10 years, the greatest amount of DSM implemented in any

single year was approximately 31 MWa in 1995, and the average annual amount over the period approximately 17 MWa.[31] PacifiCorp is rather optimistic in its IRP plans in that it expects to add 65 MWa all in one year in 2004. This assumption should be reevaluated carefully in future IRP studies.

2.6.2 Policy Results-Action Plan

The action plan is one of the most important aspects of the IRP. Utility companies develop Integrated Resource Plans to satisfy regulatory requirements, yet when it comes time to take steps towards making resource acquisition decisions, some of those companies fail to follow the key results of their IRPs. Utah's Standards and Guidelines are very clear in that they require the company to develop an action plan that will be followed in making resource acquisitions decisions once the IRP has been completed. The Standards and Guidelines state the following:

> 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. The guidelines state that the Company should include: "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."[32]

PacifiCorp's action plan is concise and developed in a way that follows the Standards and Guidelines requirements.[33] The action plan lays out the necessary steps to implement the Diversified Portfolio 1, and specifically discusses implementation efforts that the Company will follow for the first four years.

The Committee's major concern in this area is that while PacifiCorp has attempted to be specific in its approach, there are still elements of the action plan that are not clear. For example, PacifiCorp discusses the kind of analyses it will perform which includes fuel analyses, environmental analysis, etc, but there is no discussion of a critical analysis that is going to play an important role in PacifiCorp's decision making.[34] PacifiCorp is planning base load additions in 2007, 2008, and 2009;[35] but the action plan does not discuss conducting a financial analysis to determine PacifiCorp's ability to borrow money in order to finance this construction. To do this, it will have to conduct financial modeling of its entire utility system, so that it can answer the important financing questions.

[31] *Integrated Resource Plan 2003,* Table 2.1, p. 25.

[32] Public Service Commission, *Report and Order on Standards and Guidelines*, p. 41.

[33] *Integrated Resource Plan 2003*, Chapter 9.

[34] *Integrated Resource Plan*, Table 9.2.

Regarding the DSM action items that are included in the IRP, the Commission should satisfy itself that PacifiCorp has evaluated the costs of both historical and future DSM programs and that the costs of the programs are realistic.[36] In the IRP, the Company explains that existing DSM costs as much as $200/MWh to implement while, it also commits to accept only new DSM programs that are less than $39/MWh. This needs to be reconciled. Furthermore, the Company needs to present to the Commission evidence of the cost effectiveness of these DSM programs, and the reliability of the estimates of achievable levels of capacity and energy reductions. Should the benefits fail to materialize, ratepayers will be subjected to the costs of replacement power purchases from the market that may be significantly more than $30/MWh.

Concerning PacifiCorp's plans for conducting Requests for Proposals for power purchases (RFPs), the Committee believes that this will be a very important next step in PacifiCorp's resource acquisition strategy. PacifiCorp's plans to issue RFP's for DSM – Class 1 and Class 2 programs; Wind generation – (separate RFPs will be issued for both the West and East sides of the system); Renewable generation – geothermal, solar, fuel cells.

The RFP process will be crucial, as it will lend support to PacifiCorp's estimates of resource acquisition costs. The Committee believes that the Commission should closely monitor the RFP process to ensure that it is fair and equitable to all interested parties. The use of an independent third party to evaluate PacifiCorp's RFP process is something that should be discussed further with the Commission as the Company progresses towards releasing its RFP.

PacifiCorp outlines future steps that it plans to take to continue improving its IRP process.[37] For instance the IRP states that by September 2003 PacifiCorp will review its planning models, particularly with regard to the use of resource optimization logic. There are other items that PacifiCorp states that it plans to evaluate, including additional transmission analyses and evaluation of the 15% planning margin. We agree that these are important steps and would like to see PaciCorp continue to make progress analyzing these issues.

2.7 Policy Issues

As discussed above, the Committee appreciates the professionalism and dedication of the IRP team and commends the Company for undertaking a "real" planning process while addressing many of the concerns associated with past integrated resource plans. However, it appears that strategic business concerns, particularly concerns for shareholder recovery, continue to influence the resource plan in ways that may not be in the public interest.[38] Continued reliance on the market, arbitrary planning criteria that

[36] *Integrated Resource Plan 2003*, p. 155.

[37] *Integrated Resource Plan 2003*, pp. 156-157.

[38] Both the Committee and the Division in their comments to the Commission regarding RAMPP 6 noted the link between the business plan and the IRP but commented that the link may not be in the public interest. See Committee of Consumer Services, *PacifiCorp's Integrated Resource Plan, RAMPP-6, Docket No. 98-2035*, 21 December 2001, pp. 3-4 and Division of Public Utilities, *In the Matter of the*

limit plant scale and incomplete analysis of transmission options reveal this bias. As a result, whether the current Action Plan meets the Utah IRP Standards and Guidelines for least-cost is not clear. The optimality of the plan is further obscured by the lack of optimization logic in the modeling process.

2.7.1 Relation of Business Plan to Integrated Resource Plan

The Utah Standards and Guidelines state, "The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan."[39] The intent of this directive appears to be to assure that the utility is both planning for customers needs in a least-cost manner and implementing the plan.

In its comments on RAMPP 6 the Committee charged the Company with intentionally violating the intent of this directive. We noted that the Company "appears to have been positioning for a deregulated environment in which it would not have to plan for regulated load for at least the past two RAMPP cycles. PacifiCorp's internal business plan appears to have been to avoid acquiring new resources."[40] While the Committee is sincerely encouraged with the Company's renewed commitment to resource acquisition and with the steps it is taking to align its strategic business plan and IRP, we are concerned that strategic business decisions continue to unduly influence the IRP.

Full cost-recovery of existing resources and minimization of the risk to shareholders in the acquisition of future resources appear to be key components of the Company's current strategic business plan. The Company is working diligently in numerous areas including the Multi-State Process (MSP) and recent legislative sessions to increase recovery.

This strategic direction is further evidenced in several places within the IRP report including its discussion of market risks. PacifiCorp queries:

> What if independent electricity producers do not build enough supply? For years, utilities in the Pacific Northwest planned their new resource needs around the concept that there should be enough resources to cover loads even under periods of extreme drought. New Merchants may not develop resources to this level. If not, what happens if a drought then occurs? It is also possible that independent electricity producers will, at times, over-supply the market driving wholesale electricity prices below levels that recover investment costs. What if PacifiCorp develops new resources, only to find their costs higher than purchases from a temporarily depressed market? Will recovery of these "above market costs" be assured? [41]

Acknowledgement of PacifiCorp's Integrated Resource Plan (RAMPP-6), Docket No. 98-2035-05, 21 December 2001, pp. 8-14.

[39] Public Service Commission, *Report and Order on Standards and Guidelines*, In the Matter of Analysis of an Integrated Resource Plan for PACIFICORP, Docket No. 90-2035-01, 18 June 1992, p. 41.

[40] Committee of Consumer Services, *PacifiCorp's Integrated Resource Plan, RAMPP-6, Docket No. 98-2035,* p.3.

[41] *Integrated Resource Plan 2003*, p. 15.

Thus, while PacifiCorp acknowledges the risks associated with market reliance, it appears at least as concerned with the cost recovery of providing adequate resources.[42] The Committee recommends that this Commission indicate to the Company that it will not base long-run cost-recovery on short-run phenomenon.

The Company warns regulators that unless shareholders can be assured of cost recovery, implementation of the IRP may be impacted:

> A successful IRP will result in "acknowledgement" by the states indicating no significant disagreement with, and a degree of support for, the Action Plan. PacifiCorp's shareholders must and will take into account this IRP and subsequent governmental and public responses when making future capital allocation and investment decisions. Among other things, these decisions will depend on the shareholders anticipation (as communicated by their representative, the Board of Directors) of successful and economic recovery of their investment. In addition to a strong IRP acknowledgement, a successful (i.e., acceptable to all parties) MSP outcome is critical to the total success of this effort. The Action Plan results in potentially substantial financial commitments from PacifiCorp. Sustainable cost recovery of investment is an outstanding risk that must be addressed prior to such investments being made. The outcome of the MSP process will strongly influence the activities and operations of PacifiCorp, which in turn may impact the implementation of the IRP Action Plan.[43]

While the Committee cannot fault the Company for working to assure cost recovery, we are concerned that in addition to the possibility of delaying implementation, this strategic direction may have narrowed the options the Company was willing to examine in developing its portfolios. As a result, we are not assured that Diversified Portfolio 1 is optimal.

2.7.2 Build Requirement

The Committee is concerned that management's desire to minimize shareholder's capital exposure may be surfacing in modeling decisions that reduce the overall build requirement while increasing costs to customers by artificially constraining the optimum build pattern and plant scale. Of particular concern are two planning targets that serve as caps to the acquisition of long-term resources as well as limits to short-term market purchases.

As discussed above, PacifiCorp first establishes its need for resources. To fill its deficit it adds resources until the system is short not more (and not less) than 5% of the hours in a year. This level results in approximately a 12% reserve margin. The Company then adds peaking resources until a 15% reserve margin is reached. Portfolios meeting the market reliance and reserve margin criteria are subjected to further analysis including risk analysis.

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[42] *Integrated Resource Plan 2003*, p. 15.

[43] *Integrated Resource Plan 2003*, p. 151-152.

The market-reliance criterion and the reserve-margin criterion functioned as screening devices for the Company. It used the criteria to winnow out portfolios that did not have adequate resources and relied too much on the market prior to further analysis. However, it also used the criteria to winnow out portfolios that added resources in excess of these criteria.[44] The Committee is concerned that portfolios with a lower present value of revenue requirement (PVRR) but less market reliance and larger reserve margins may have been discarded prior to risk analysis.[45] We are not convinced, therefore, that these arbitrary decision criteria allow discovery of the optimal portfolio.

While the Company's decision to go to the short-term market no more than 5% of the hours in a year may sound benign, the Committee notes that the risk could be significant depending on the location and timing of the short position.[46] At an extreme it could represent half the summer high load hours on the East Side of the system. This level of market exposure could have severe financial consequences if the west is not overbuilt and suffers another drought. And, since all the portfolios that were analyzed for risk relied on the 5% criterion, the risk analysis that was undertaken could not distinguish between portfolios of different sizes.

The Committee therefore believes the basis and impact of this arbitrarily imposed criterion requires further analysis. We also recommend that this criterion be examined in relation to the decision to model average hydro conditions rather than critical hydro.[47] While reliance on the market for 5% of hours may be reasonable if resources were modeled assuming critical hydro conditions, it may not be reasonable given the assumption of average hydro. In times of drought, the surplus energy built into the average water assumption will not be available, and relying on the market for 5% of total hours may be costly indeed. Finally, the decision to model resources using average hydro rather than critical should be thoroughly examined.

A 15% planning reserve margin appears to be a reasonable minimum-planning margin, however, the imposition of the reserve margin as an upper limit requires justification. To limit the reserve margin limits the size of baseload that can be added at any one time, and is counter to past PacifiCorp strategies.[48] PacifiCorp's analysis in the current IRP supports the notion that larger portfolios providing substantial baseload capacity result in

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[44] This was established during public process meetings and is evidenced by the reserve margins in each year. The highest reserve margin in any year in the Diversified Portfolio 1 is 17.6% in 2009, which is not significantly higher than the 15% minimum requirement.

[45] Prior to establishing the 5% of hours market purchase criterion, the Company had developed representative portfolios. Company personnel indicated that they discarded portfolios that did not meet the newly established target criteria regardless of whether the portfolio had a lower PVRR than those they retained.

[46] "Short-term and spot market electricity purchases supplied 20.5% of PacifiCorp's total energy requirements in 2002." *Integrated Resource Plan 2003*, p. 30.

[47] RAMPP 2 used critical hydro. Subsequent IRPs have relied on average water.

[48] PacifiCorp pursued a surplus strategy in the early 1990s as described in RAMPP-2and discussed in the Comments of the DPU on RAMPP-6.

more favorable PVRR's than those based on peakers and market purchases.[49] PacifiCorp notes that the top scoring portfolios are those that provide high amounts of excess non-peak power.[50] PacifiCorp also notes that, "While significant, the low-side risk of a long-position pales in comparison to the risk of a chronically short position."[51] It further states: "the magnitude of net power cost upward excursions are virtually unlimited while the magnitude of downward excursions is limited by the high probability that prices will remain positive."[52]

In light of the above discussion, the decision to discard portfolios with reserve margins in excess of 15%, regardless of the PVRR, prior to risk analysis is troubling. It is difficult to attest to the least-cost nature of the expansion plan if larger portfolios with lower PVRR were discarded. We, therefore, recommend that the Commission require additional runs that relax the reserve margin limit in the future. If PacifiCorp has financial reasons for limiting the build size, it should address them directly.

2.7.3 Transmission Options

The Committee does not believe the Company adequately evaluated transmission alternatives in its portfolio development. The Committee has three immediate areas of concern: incremental transmission additions were not modeled; wheeling revenues to offset the expense of the addition of major new lines were not modeled; and alternative generation resources as part of the *East-West Transmission Portfolio* were not modeled.

PacifiCorp considered two general transmission alternatives. The first, PacifiCorp's *East-West Transmission Portfolio,* added a PacifiCorp owned DC line from the Wasatch front to Malin, Oregon and added enough thermal resources on both the East and West Sides to meet energy needs. Capacity was added to a 10% planning margin. Two sizes of DC line were evaluated. The second, *Transmission to Asset Build Market,* built transmission to generation resources built and owned by other parties in the southern Nevada region. The transmission portfolios were not competitive with other portfolios that PacifiCorp evaluated.

The Committee is concerned that the poor performance of transmission alternatives is a result of incomplete modeling. In both portfolio subcategories, PacifiCorp assumed it built and owned the transmission and did not allow for third party participation or use. In both alternatives PacifiCorp built major new lines rather than evaluating upgrades to existing lines. Finally, in the *East-West Transmission Portfolio* the Company assumed that the only benefit of adding a line was to reduce the need for system capacity from 15% to 10%. It still met energy needs by locating resources near load centers.

The decision to assume no third party wheeling revenues is inconsistent with the modeling of generation alternatives that credit off-system sales, thereby reducing the PVRR. If wheeling revenues were included, the PVRR of these alternatives would be

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[49] *IRP 2003*, p. 100.

[50] Ibid. p. 103.

[51] Ibid. p. 20.

[52] Ibid. p. 54.

reduced. The Committee believes transmission options should be evaluated in a like manner to generation resources. Furthermore, the Committee would like to see transmission upgrades evaluated as an alternative to siting new transmission facilities. Finally, the Committee questions why the Company did not consider combing additional coal resources in the east with the new transmission line in the *East-West Transmission Portfolio* when adding a transmission line. Historically, DC lines have been added to supply energy.

The Committee's concern with the limitations in the modeling of transmission alternatives runs deeper than mere technical corrections. We question the reasons behind the decision to model transmission in the manner it was modeled. It seems reasonable to us that the Company has no desire to seriously consider transmission additions or transmission alternatives that would build more energy on once side of its system than the other because of the extent of the paradigm risk, particularly to shareholders, posed by RTO West and by the potential for differing state energy policies.

In the IRP report, the Company addresses its concern regarding the cost-recovery risk RTO West poses to shareholders. It states: "the major uncertainty associated with the transmission portfolios is the potential impact of the RTO West. There are still unknowns related to who will pay for the cost and the mechanism in place for recovery of transmission investments."[53]

Managing the risk to shareholders posed by differing state energy policies has been a major focus of the Company for several years. It was the basis for its December 2000 SRP filing, the precursor to the current MSP process. Within the MSP forum, the Company has expressed a strong preference for conducting cost allocation and long-term planning along East-West control-area divisions in order to minimize cost-recovery risk. It has expressed concern that the west will not pay for eastern growth and that the west will not pay for coal resources. Portfolios that strengthen the East-West connection and add additional coal-based energy do not appear consistent with the Company's strategic business plan.

While the Committee sympathizes with the extent of the uncertainty posed both by RTO West and by differing state policies, we believe the proper approach within the IRP is to adequately model the full range of portfolio alternatives including transmission and then evaluate the potential impact of the scenario risk to both customers and shareholders. This information would feed into the division of customer and shareholder risk.

2.7.4 Customer and Shareholder Risks

The guidelines state that the Company should include: "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."[54] For clarification of the meaning of this guideline,

[53] *IRP 2003*, p. 85.

[54] Public Service Commission, *Report and Order on Standards and Guidelines*, p. 44.

the Company conferred with Commission staff and identified two issues, which PacifiCorp states in the following manner:

1. Is PacifiCorp's participation in the market or in resource development for the benefit of shareholders? If benefits accrue to both customers and shareholders, a clear understanding of risk allocation is critical.

2. If PacifiCorp mitigates regulatory risks through the IRP are costs borne by ratepayers to reduce shareholder risk?[55]

The Company identifies the benefit to shareholders as the opportunity to earn the allowed rate of return on investments resulting from the plan. It identifies its risks as regulatory risks arising in the implementation of the IRP. The risks include regulatory lag, allocation gap, normalization and disallowance.

The Company states "customers face all of the risks evaluated in the IRP"[56] however they receive all of the benefit:

> The customers will receive all the benefit of a successfully implemented IRP by receiving low-cost, stable cost, reliable, and well risk-managed power supply. Other than the opportunity to earn a fair rate of return on shareholder investments, subject to regulatory risk… PacifiCorp's shareholders are neutral to the IRP decisions.[57]

The purpose of the Committee's discussion in sections 2.7.1, 2.7.2 and 2.7.3 was to establish that the Company does not appear to be neutral to IRP decisions but does indeed have a preference for alternatives that limit the capital exposure of new generating resources and the paradigm risk associated with transmission options. It appears to us that PacifiCorp is attempting to mitigate the regulatory risk of cost recovery through its IRP. The result is a portfolio that may or may not be least-cost. To the extent that the Company's shielding of shareholders results in higher overall costs, shareholders should bear that risk.

3.0 RECOMMENDATIONS

The Committee recommends that the Commission acknowledge the Company's current IRP, *Integrated Resource Plan 2003*. We are pleased by the Company's apparent commitment to the acquisition of resources to meet the needs of its regulated customers. However, we cannot attest to the least-cost nature of the plan and are concerned for the following reasons:

- Automatic resource addition logic was not used;
- Transmission was not modeled thoroughly;

[55] *IRP 2003*, pp 52-53.

[56] Ibid. p. 54.

[57] Ibid. p. 56.

- The criteria for market reliance and the planning reserve margin were arbitrarily chosen;
- DSM historic costs and future program modeling costs show a distinct disconnect.

Therefore, the Committee makes the following recommendations to be incorporated during the continuing cycle:

3.0.1 The Commission requires PacifiCorp to acquire and use a model that incorporates automatic resource expansion logic as a screen prior to risk analysis.

3.0.2 PacifiCorp should reevaluate the amount of cost-effective DSM that can be added in one year and provide details of how cost-effectiveness is evaluated.

3.0.3 PacifiCorp officially reconcile the differences in program costs between the existing DSM programs in the 2001 time period, and the new programs that PacifiCorp is evaluating as part of its IRP.

3.0.4 The assumption that the earliest that any wind resources are added on the system is 2006 should be reevaluated.

3.0.5 The assumption of zero capacity credit for wind power resources should be reevaluated.

3.0.6 PacifiCorp should consider either adding a new unit earlier or planning more long-term firm capacity purchases.

3.0.7 PacifiCorp should incorporate path analysis, financial analysis, and rate analysis as part of the IRP.

3.0.8 PacifiCorp should evaluate smaller scale transmission upgrades and include an estimate of wheeling revenues in evaluating transmission alternatives.

3.0.9 Transmission options should be evaluated in a like manner to generation resources.

3.0.10 The basis and impact of the 5% market hours limitation and the 15% planning margin should be further analyzed.

3.0.11 The Commission should require additional runs that relax the reserve margin limit.

3.0.12 The above criterion should be examined in relation to the decision to model average hydro conditions rather than critical hydro.

3.0.13 The decision to model resources using average hydro rather than critical should be examined.

3.0.14 The Commission indicates to the Company that it will not base long-run cost-recovery on short-run phenomenon.