Integrated Resource Plan
2003

Assuring a
bright future
for our customers

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This Integrated Resource Plan (IRP) is based upon the best available information at the time the IRP is filed. The Action Plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the Action Plan no less frequently than annually. Any refreshed Action Plan will be submitted to the State Commissions for their information.

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2002 INTEGRATED RESOURCE PLAN EXECUTIVE SUMMARY

SUMMARY

The purpose of PacifiCorp's Integrated Resource Plan (IRP) is to provide a framework for the prudent future actions required ensuring PacifiCorp continues to provide reliable and least cost electric service to its customers. The IRP was developed with considerable public involvement from customer interest groups, regulatory staff, regulators and other stakeholders. PacifiCorp is filing this IRP with its State regulatory agencies and requesting that they acknowledge and support its conclusions, including the proposed Action Plan.

This IRP is developed against the backdrop of continuing market, regulatory and structural changes in the electric industry. These changes highlight the importance of understanding the risks and uncertainties inherent in resource planning. This IRP uses a robust and objective analytical framework to simulate the integration of new resource alternatives with PacifiCorp's existing generation and transmission assets, and to compare their economic and operational performance. The methodology also accounts for the uncertain future by testing resource alternatives against measurable future risks and possible Paradigm shifts in the industry.

The IRP reveals that PacifiCorp has substantial new resource needs. Looking forward, PacifiCorp expects its obligations to provide electricity to its customers will continue to grow, while at the same time its existing resources will diminish significantly. Load growth, load shape growth, asset retirement and contract expirations cause the gap between demand and supply to grow over time. Measures need to be taken to close the gap, and a number of diverse actions are proposed. Not taking prompt and focused action to close this gap would expose PacifiCorp and its customers to unacceptable levels of cost, reliability and market risk.

Other key findings in the IRP include:

- The strongest resource strategy relies on a diverse portfolio of options, including strong components of renewables and demand side management, but also natural gas- and coal-fired generating resources. A resource procurement process to pursue this diversified approach is described in the Action Plan.
- Possible Paradigm shifts in the electric industry driven by Federal regulatory requirements are significant uncertainties for PacifiCorp and its customers to manage in the next several years. These issues include (potentially favorable) changes in transmission operations, as well as the potential increased costs associated with PacifiCorp's existing resource assets, including complying with air emission standards and relicensing hydroelectric facilities.
- Renewable resources are a good fit for PacifiCorp within the context of a diversified portfolio. The IRP proposes procuring renewable resources (primarily wind, and possibly geothermal) at a level shown to be cost effective, given the assumptions used to evaluate the resource. The amount of renewables is also a level that would meet or exceed renewable portfolio standards that have been proposed in Federal and State legislation.

- Demand-side management (DSM) will continue to be an important and cost-effective program for PacifiCorp. A significant increase in programmatic measures is proposed, including a load control program to help mitigate growing capacity requirements.
- In addition to renewable resources and DSM, the study concludes that additional resources from thermal generation will also be required. The least cost option is a combination of three natural gas-fired units and one coal unit to meet both growing energy and capacity requirements.
- The least cost portfolio includes a coal baseload thermal unit in the East. Coal-fired generation may be particularly advantageous when procuring resources in the Rocky Mountains because coal is an abundant indigenous resource there. However, the long-term impacts of atmospheric emissions are casting doubt on the viability of coal-fired generation. The IRP least cost portfolio is dependent upon the impact of a number of these Paradigm risks, including air emission standards and possible global warming measures. PacifiCorp believes it has adequately addressed these risks, based on our current understanding of them, and coal plants remain a low-cost option. The IRP Action Plan includes further work to develop and test the viability of a coal baseload thermal unit, including an ongoing assessment of the risks.

This IRP proposes a significant procurement of new resources. The strategy outlined in this IRP includes the addition of about 4,000 MW of new capacity over the first ten years of the 20-year IRP. The least-cost, risk-adjusted approach proposed is a diverse portfolio of resources, including renewables, DSM, and thermal baseload and peaking units. These additions include the following portfolio additions during the planning period:

- 1,400 MW of renewable resources
- 450 MWa of DSM and 90 MW of direct load control
- 2,100 MW of baseload capacity
- 1,200 MW of peaking capacity
- 700 MW shaped resource contracts

The Action Plan details findings of resource need and specific implementation actions. The Plan also outlines step-by-step decision processes by which proposed resources will be continually evaluated and procured. Going forward, PacifiCorp will implement the Action Plan, while also maintaining the flexibility to adjust to future changes and opportunities. The Action Plan will also be revisited and refreshed no less frequently than annually.

For analytic purposes, the IRP assumes new resources are developed and owned by PacifiCorp. However, no decision has been made to invest in specific resources. The decision to own, build and invest in a new resource versus contracting with a third party will be made as part of the procurement process for each new resource addition, and on a case-by-case basis. A Multi-State Process (MSP) will provide clarity on the regulatory treatment of investment decisions and the degree of cost recovery risk held by PacifiCorp. The MSP is expected to issue findings in the spring, 2003. The MSP outcome will influence the activities and operations of PacifiCorp, and may impact Action Plan implementation.

A significant procurement program and potential investment is required to maintain reliable electric service. It is critically important that State regulators support this IRP and issue their acknowledgement of the Action Plan. This support coupled with a useful and durable MSP outcome is vital to PacifiCorp being able to resolve issues around recovery lag and achieving allowed rates of return, and continue to provide low cost, reliable service to its customers.

THE CHANGING CONTEXT FOR RESOURCE PLANNING

The electricity industry continues to evolve due to regulatory changes and market forces. The volatility and uncertainty in the industry has increased in a number of areas. Through overt public policy and an emerging industry structure, the wholesale competitive marketplace has evolved. Market price uncertainty remains a concern, as was highlighted by the dramatic volatility in West-wide electricity prices during the 2000-2001 period. Federal regulatory changes are likely to be significant, particularly with regard to how transmission will be controlled and operated in the future. Nation-wide, natural gas-fired generation has emerged as the industry's thermal resource of choice, and this growth in the reliance on natural gas increases supply and price uncertainty. Throughout this evolution PacifiCorp's obligation to serve remains inviolate.

These ongoing changes in the structure and regulation of the industry require changes in the approach to resource planning. Given the potential for commodity markets (both natural gas and electric) to exhibit rapid price swings, or volatility, alternative resource plans must be evaluated in terms of their exposure to this volatility, in addition to their long-run average costs. Furthermore, unpredictability in the future costs of new supply alternatives arising from fuel cost (primarily natural gas price) and emissions cost uncertainties must be recognized. Finally, the rapidly evolving structure of markets and their attendant risks demand a more timely and responsive process for keeping IRPs current. This IRP represents PacifiCorp's efforts to adapt its resource planning to these requirements. The IRP provides analysis leading to a comprehensive portfolio and strategy for supply acquisitions, transmission investments and demand-side management that balance low cost with risk to result in the long-run least cost solution.

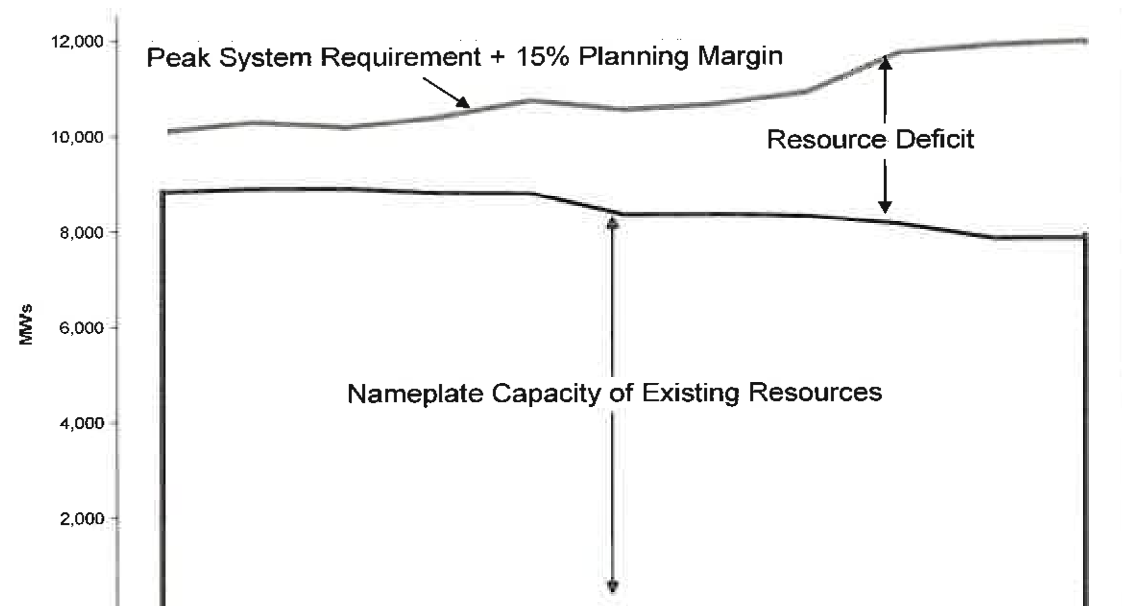
CURRENT POSITION

PacifiCorp serves approximately 1.5 million retail customers in service territories comprising about 135,000 square miles in portions of six Western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The service territory has diverse regional economies ranging from rural, agricultural, and mining areas to urban, manufacturing, and government service centers.

PacifiCorp forecasts load on its system to grow by 2.2% in the East and 2.0% in the West per year, on average. Given uncertainties of economic growth and other factors, this growth in PacifiCorp's load could vary between 1.4% and 3.4%. At the same time, the resources available to PacifiCorp to serve this demand will diminish over time as supply contracts expire, hydroelectric generation facilities are subjected to relicensing conditions and thermal plants comply with more stringent emissions requirements. This creates an imbalance that is referred to as the *gap*. This gap between loads and existing resources will grow through time.

The load forecast and the existing PacifiCorp resources define the shortfall in supplies. The figure below is an illustration of PacifiCorp's peak system requirement with a 15% planning margin compared to the capacity of the existing resources as they are expected to exist in the future. Use of this assumption does not presume 15% is the ideal level for reliability purposes. More or less planning margin could be warranted. Rather, the assumption is consistent with the ranges discussed under the FERC Standard Market Design (SMD) proposal, and reinforced by the public input process.

PacifiCorp System Capacity



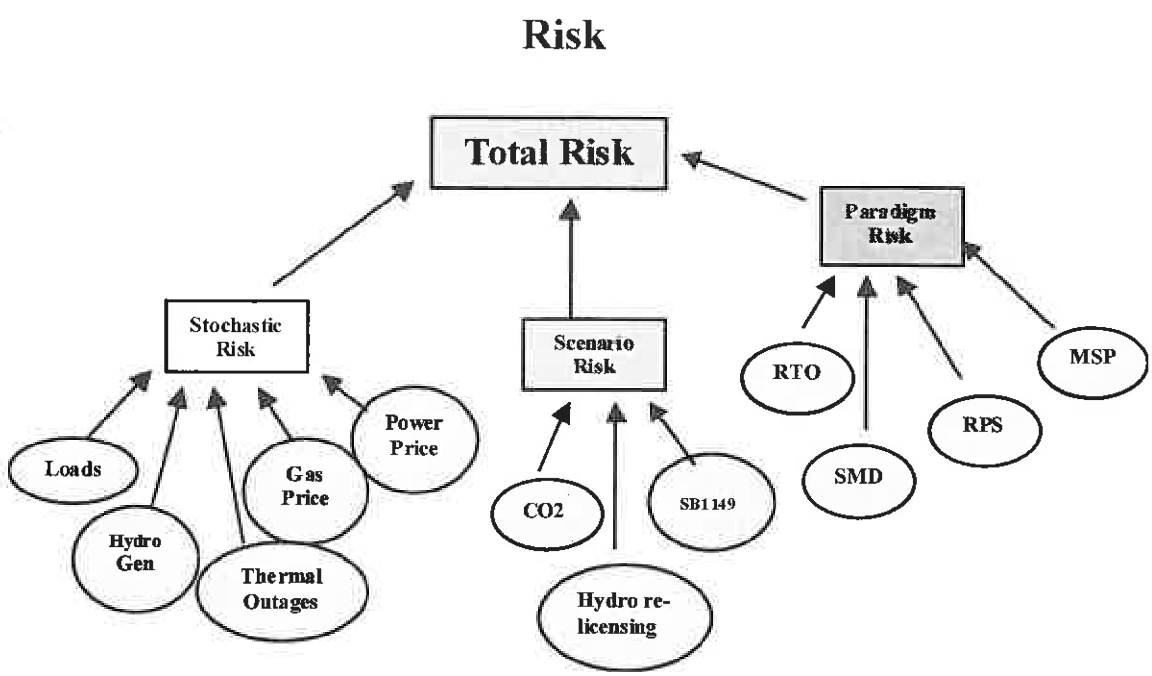
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Pk Rqmt + 15%	10,090	10,288	10,176	10,379	10,731	10,531	10,641	10,893	11,712	11,869	11,936
Existing Capacity	8,833	8,894	8,893	8,800	8,788	8,335	8,335	8,299	8,119	7,820	7,820

Calendar Year

While the exact size of this gap is uncertain, PacifiCorp expects it will require an additional 4,000 MW of new resources (DSM, generation, and supply contracts) through 2013. Understanding the size and timing of the gap, as well as the seasonal and hourly shape of existing loads and resources, is a fundamental driver with this IRP. It drives the overall need for new resources, the appropriate balance between baseload and peaking requirements, the transmission needs and demand side management decisions.

RISK AND UNCERTAINTY

Clearly, resource planning must consider many future risks and uncertainties. While the need for planning under uncertainties has been clear for some time, general techniques for effectively incorporating risk analysis into utility resource plans have been more elusive. PacifiCorp has adopted a new methodology to evaluate how alternative resource options perform against the risks and uncertainties in three categories: Stochastic, Scenario and Paradigm risks. The figure below provides an illustrative example of these risks (the acronyms are defined below).



Stochastic Risks

Many risks facing PacifiCorp are quantifiable business risks and are referred to as Stochastic risks. The expected variability in Stochastic risk parameters, such as in electricity price, for example, can be derived from historical experience and simulated. The resource planning analysis assumes that these stochastic risks are driven by uncertainty in the following parameters (risk factors):

- Retail load forecasts
- Natural gas prices
- Spot market electricity prices
- Hydroelectric generation
- Thermal unit availability

Scenario Risks

Other risks that are evaluated quantitatively in this IRP are scenario-driven, such as the introduction of high carbon taxes. The probability of high carbon taxes cannot be determined based upon historical experience, so a scenario is created without applying a probability. In the case of changing Scenario risks, the time evolution of the Present Value of the Revenue Requirement (PVRR) takes a distinctly different path, rather than fluctuating around an expected value. The measure of Scenario risk is the difference between the expected PVRR generated by applying different scenarios.

Scenario risks addressed include:

- Charges for prospective CO2 emissions
- Effect of relicensing outcomes on future hydroelectric generation cost and availability
- The market value of Green Tags, as influenced by the possible passage of Federal and State renewable portfolio standards
- Limits to the availability and liquidity of spot market purchases, as an alternative to procuring resources
- Potential for ongoing renewable production tax credits

Paradigm Risks

Significant structural changes to the electricity business model associated with a large shift in market structure or regulatory requirements are treated as Paradigm risks in the IRP. The key Paradigm risks considered within this IRP include:

- Structural changes in operation and control of transmission promulgated by the Federal Energy Regulatory Commission (FERC) rules including potential formation of a regional transmission organization (RTO) and the SMD proposal
- Federal legislation that could establish a Renewable Portfolio Standard (RPS)
- The outcome of the pending multi-State discussions (MSP) addressing PacifiCorp's method of regulation and cost recovery

Since the details of such changes are not presently specified, Paradigm risks do not lend themselves to quantitative analysis. Structural changes to fundamentals generally defy reasonable approaches at numerical representation. While not explicitly modeled, Paradigm risks cannot be ignored. Accordingly, Paradigm risks are addressed qualitatively. In some instances, assumptions are explicitly modeled to impute additional flexibility. Despite these efforts, Paradigm risks, as they arise, ultimately require a well reasoned response arrived at in conjunction between PacifiCorp, its regulators and the public. The flexibility to respond to changes in the Paradigm environment is an element of the Action Plan.

ANALYTICAL APPROACH

This IRP uses a robust analytical framework to simulate the integration of new resource alternatives with PacifiCorp's existing generation and transmission assets. The model includes hourly data granularity and consideration of market trading hubs, and transmission paths and constraints, to provide a detailed examination of the economic and operational performance of resource alternatives.

The starting point for the analysis is the determination of the gap between growing loads and existing resources, discussed above. From this starting point, the analysis involves a number of distinct steps:

- **Portfolio Development**: The first step is the formulation of resource portfolios. Formulating the portfolios requires specifying the types and timing of resource additions such that anticipated loads are reliably served. Portfolios were chosen to span a complete range of likely resource strategies.
- **Operational Simulation:** Next, the operation of each portfolio is simulated. The simulation develops a base or reference view of the future. In so doing, this step requires calculating the operating costs of the integrated system (both the portfolio additions and the existing resource system) and other performance characteristics under a representative set of assumptions about the future.
- **Cost Analysis:** Each portfolio's system operating costs are combined with the corresponding capital costs, yielding the PVRR, the main cost metric.
- **Screening:** Performance measures (PVRR and others) are used to screen the portfolios. Focusing only on portfolios that survive this winnowing allows risk analysis to be performed on the most promising portfolios.
- **Risk Analysis & Stress Testing:** 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 in a portfolio's cost.
- **Portfolio Refinement:** Based on these results, iterative improvements to the best performing portfolios are made, defining hybrid portfolios that are tested against each other to identify the least cost, risk-adjusted portfolio.

Four key assumptions were particularly important to the analytical approach:

- Where possible, the analytical approach presumed new resources were actual specific assets. This allowed precise modeling of different site, technology and transmission costs. In practice, as seen in the Action Plan, new development will be rigorously compared to alternative purchase options and "then-appropriate" asset definitions that include current technology, specific siting and tailored asset capacity. Such a program assures new resources are ultimately obtained from the least cost provider.
- The analysis conservatively assumed no renewal of long term contracts. The modeling approach assumed future resources are obtained at market prices and that the costs of long-term contracts converge on such prices. From an economic and modeling standpoint further distinctions are unnecessary.
- Since PacifiCorp has a well-defined obligation to serve load, only firm transmission was included to ensure that it was always available to provide service. This is another conservative assumption matching PacifiCorp's load serving obligations. Ignores 8&8
- All portfolios were built to closely match load growth, plus a 15% planning margin. While the model assumed system sales occur for balancing purposes, new resources were not added for merchant purposes.

Modeling was performed on a system basis. Although the transfers between the East and West systems were measured and reported, State specific impacts were not assessed. It is expected that these issues will be addressed in detail following the conclusion of the MSP discussions.

RESOURCE ALTERNATIVES

There are a large number of demand side and supply side options that could be used in filling the gap between PacifiCorp's known resources and prospective load obligations. The IRP focuses on the candidate options that are considered realistic, feasible alternatives for balancing resource supply with electricity demand. Key resources that may be economical and could feasibly be procured by PacifiCorp to meet customer needs include:

- Demand side management programs
- Transmission alternatives
- New generation investment or purchase based on energy sources such as:
  - Wind
  - Coal
  - Geothermal
  - Combined heat and power (i.e., cogeneration)
  - Fuel cells
  - Natural gas (peaking and combined cycle units)
- Repowering or expanding existing PacifiCorp resources
- Market purchases and shaped products
- Transmission

Other resource technologies exist, but were not considered feasible for meeting PacifiCorp's resource needs. These include nuclear resources, tidal action resources, micro-turbines, and others that are either not commercially available or have not yet proven to be cost effective. However, three options that are currently not being included in IRP portfolio analysis due to cost, but are being monitored closely for future use, include "clean" coal technology (IGCC), pumped storage and solar resource options.

PORTFOLIOS

To explore a broad range of possible resource mixes, portfolios were initially developed in three different categories: thermal, alternative technology and transmission. The different categories were compared to learn operational differences based on resource type under varying assumptions. Based on this analysis, several hybrid portfolios were developed by taking the best of all portfolios and combining them to achieve the least-cost solution.

Common Features of Portfolios

Several resource additions are common to all portfolios and contribute substantially to future resource requirements. All portfolios share base DSM investments, beginning in 2004 and steadily increasing their contributions. The portfolios also all include a base level of renewables resources. Initially, these were wind additions based on the level required in the proposed Federal RPS. However, in the final portfolios, the analytical approach to renewables was refined, and renewables were included based solely on the economic merits. All portfolios also include purchases to meet capacity and energy needs for the 2004-2006 period (the period in which long-term procurement options are limited).

Draft IRP?

Thermal Portfolios

The portfolios in the thermal category contain a mix of coal and natural gas additions. There were four subcategories of thermal portfolios: Diversified Gas/Coal, Diversified Coal/Gas, All Gas, and PacifiCorp Build. Each subcategory contains individual portfolios that were used to test the timing and size of resource additions.

The thermal options have good prospects for siting and licensing generation, since PacifiCorp currently controls existing thermal generation sites with room for expansion. Another benefit to the thermal portfolios is that PacifiCorp can make use of existing transmission corridors. Finally, PacifiCorp currently has experience with building, owning and operating thermal facilities. Key uncertainties associated with thermal portfolios are the impact of future environmental legislation, future natural gas price volatility, and regulatory cost recovery.

Alternative Technology Portfolios

The purpose of the Alternative Technology portfolios was to continue to test the strategy that replaced thermal plants with a more aggressive resource program focused on conservation and alternative technologies. This was accomplished by adding additional wind plants, over and above the anticipated Federal RPS, as well as geothermal plants, fuel cells, combined heat and power (CCHP) and additional DSM. Natural gas-fired plants (CCCTs and Peakers) were used to fill the energy balance and build the portfolio to the required 15% planning margin.

Alternative technology portfolios perform particularly well in reducing emissions and providing diversification in PacifiCorp's overall resource portfolio, which helps mitigate fuel price risks. There are significant uncertainties with an aggressive renewables portfolio. The uncertainties identified include:

- Fuel cells are not a proven technology that has been widely dispersed in the utility industry
- The size and timing of the resource addition requirement that is daunting particularly with respect to amounts of required capital component and suitable sites.
- Quality and location of potential wind sites, and associated transmission which have not been identified.
- Integration costs associated with the wind plants need additional study, including regulating margin uncertainty, balancing charges for natural gas supply, and changes in integration costs as a function of amount of wind capacity installed.
- Assumptions surrounding the Green Tags and Production Tax Credits, which also represent uncertainty.
- Specific incremental DSM programs have not been identified or modeled in these portfolios

Transmission Portfolios

Portfolios in this category increase system transmission capability to markets and between PacifiCorp control areas and load centers. There are two subcategories of transmission portfolios: East-West Transmission and Transmission to Asset Markets. For East-West transmission, a DC line was constructed from the Wasatch front to Malin, Oregon to allow better flexibility to transfer electricity from the East and West control areas. For Transmission to Asset

Markets, transmission access to markets is increased with assets built by other parties, and concentrates on building lines to southern Nevada.

Constructing a DC line that connects the East and West control areas potentially allowed for greater system flexibility and greater utilization of existing resources, and could reduce the necessary planning margin. Increased transmission access to markets would allow PacifiCorp access to markets, and reduce the capital requirement necessary to construct new plants. Major uncertainties associated with the transmission portfolios included the impact of RTO West as well as siting and permitting difficulties. Transmission should be looked at on a WECC-wide basis in order to capture further potential system wide benefits.

Hybrid Portfolios

After the initial portfolios were developed, analyzed and screened, hybrid portfolios were structured using the best characteristics of the results. Five hybrid portfolios were created – Renewable, Diversified I, Diversified II, Diversified III and Diversified IV. The Renewable portfolio was created by removing the fuel cells, CHP, and DSM from the Alternative Technology II portfolio, and adding a CCCT at Mona in 2009. The diversified portfolios were developed using the top four thermal portfolios in each sub-category (Gas/Coal, Coal/Gas, All Gas, and PacifiCorp Build), and with the gradual, profiled wind used in the Renewable and Alternative Technology II portfolios.

RESULTS AND CONCLUSIONS

The portfolios were studied and compared for their operating and economic performance, in combination with PacifiCorp's current resources and the operational features and constraints of the electric system. This analysis yielded a large body of results. The operational results were further tested for their robustness to risks and stress tested against potential outcomes of important Scenario and Paradigm risks. The portfolios were also compared from a customer impact perspective. This analysis helped to identify the context and meaning of the portfolio studies and how they compared to each other. Through this extensive and iterative process, the least cost portfolio was identified and confirmed to perform well against risks and uncertainties.

The conclusion reached through this analysis is that Diversified Portfolio I is the least-cost, least-risk portfolio to fill PacifiCorp's long-term resource needs. In support of this conclusion are a number of findings.

- Diversified Portfolio I produces the lowest PVRR and lowest risk profile of the portfolios studied.
- In relative terms, the portfolios are close in PVRR. The five hybrid portfolios ranged from 0.2% to 3.6% above the PVRR of Diversified I. Given the time period of the study and the large number of inputs considered, these differences could arguably be described as statistically insignificant.
- Portfolios with higher fixed costs tend to yield even greater reductions in variable cost requirements. The Diversified I portfolio has the greatest real levelized fixed cost and the least incremental net variable cost of the top portfolios.

- Exposure to natural gas prices appears to be a leading contributor to the risk differences in the portfolios. The Diversified I portfolio featuring the addition of a coal plant with the earliest installation schedule has the least natural gas exposure.
- The evolution of Paradigm and Scenario risk factors could change resource decisions and warrants a plan with flexibility.

The actions related to procuring the resources identified in Diversified Portfolio I are the basis for the Action Plan.

ACTION PLAN

The Action Plan aims to ensure PacifiCorp will continue meeting its obligation to serve customers at a low cost with manageable and reasonable risk. At the same time, the Plan remains adaptable to changing course, as uncertainties evolve or are resolved, or if a Paradigm shift occurs. An element of the Action Plan is to preserve PacifiCorp's optionality and flexibility in the future.

The Action Plan is based upon the best information available at the time the IRP is filed. It will be implemented as described, but is subject to change, as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the Action Plan no less frequently than annually. Any refreshed Action Plan will be submitted to the State Commissions for their information. The Action Plan will also be revised as a consequence of subsequent IRPs.

Included in the Action Plan are:

- A detailed plan, including specific Findings of Need and Implementation Actions
- The Decision Processes for implementing the Action Plan
- The Procurement Program for implementing the Action Plan
- An update on PacifiCorp's Current Procurement and Hedging Strategy
- Description of how PacifiCorp Resource Planning and Business Planning are aligned
- Discussion on the Action Plan's consistency with the Oregon's restructuring legislation (SB-1149)

Key elements in the Action Plan to implement Diversified Portfolio I include:

- Demand Side Management (DSM) – 450 MWa to reduce overall system demand and peak requirements
- Renewables – 1,400 MW of primarily wind resources but also potential geothermal resources
- Baseload Resources – 2,100 MW to cover load growth, plant retirement and contract expiration across the PacifiCorp system. This includes three units in the East (one fueled with coal and two with natural gas) and one natural gas unit in the West. However, PPA's could replace the need for building assets as a result of the Decision Processes and Procurement Program for implementing the Plan

- Peaking Resources – 1,200 MW in natural gas-fired units to address the pronounced system peak
- Transmission – upgrades and additions to further optimize the use of the network, provide greater access to market, and support the addition of new generating assets
- Shaped Products and Power Purchase Agreements – 700 MW to resolve immediate energy requirements prior to physical assets being built and to support optimization of the portfolio.

In implementing the Plan, all resource options will be rigorously compared to alternative purchase options either from the market or from other existing potential electricity suppliers. The Action Plan includes Decision Processes and a Procurement Program to assure new supplies ultimately are obtained from the least cost source. The proposed Procurement Program will also ensure consistency with anticipated ratemaking requirements, including industry restructuring implementation in Oregon.

PacifiCorp is seeking acknowledgement of the Action Plan by regulatory Commissions in five States. How these Commissions will treat a favorable acknowledgement of an IRP Action Plan in subsequent rate cases may vary. To accommodate potential differences in treatment of an acknowledgement, the detailed Action Plan provides both specific findings regarding the need for resources, and details the implementation actions to address the findings of need. The Findings of Need and Implementation Actions are consistent with each other and support the implementation of the Diversified Portfolio I.

This IRP provides the rationale for PacifiCorp's resource procurement going forward. The Action Plan contemplates a potential substantial financial commitment from PacifiCorp. Sustainable cost recovery of investment is an outstanding risk that must be addressed prior to such investments being made. MSP is currently addressing this issue and is expected to issue findings in spring, 2003. The outcome of the MSP discussion will strongly influence PacifiCorp's ability to implement this IRP Action Plan.

It is critically important that State regulatory commissions efficiently acknowledge and support this IRP, including the Action Plan. This support coupled with a useful and durable MSP outcome will enable PacifiCorp to resolve issues such as recovery lag and achieving allowed rates of return. PacifiCorp's current and potential shareholders as well as the financial community must and will take into account the governmental and public response to the IRP when making capital allocation and investment decisions. Among other things, these decisions will depend on investors' anticipation of successful, timely and economic recovery of this investment. A successful MSP outcome along with a Regulatory acknowledgement of this IRP, are both critical in ensuring PacifiCorp can continue to provide reliable and least-cost electric service to its customers.

1. MARKETPLACE & FUNDAMENTALS: THE CHANGING CONTEXT OF INTEGRATED RESOURCE PLANNING

The overriding objective of integrated resource planning, to develop a firm plan for the lowest cost resources for a utility and its customers, is sensible and enduring, but the practice of planning must be adaptive to changing circumstances. This chapter provides an overview of emerging trends and recent developments in PacifiCorp's situation and in the Company's evolving business environment that leads to the conclusion that lowest cost must be balanced with lowest risk to produce the most economic solution.

PLANNING UNDER UNCERTAINTY

The competitive marketplace in the electric power industry has grown in importance and introduced new opportunities and risks to PacifiCorp's future supply portfolio. Future natural gas price uncertainty, in light of this fuel's prominence in new electricity plants, contributes to a more complex and uncertain future, as does the potential for additional limits or penalties on emissions from generators. These trends and uncertainties expose PacifiCorp and its customers to new and significant risks that must be recognized in the preparation of the integrated resource plan. Although these risks cannot be eliminated, the IRP can help manage them by:

- Recommending new resource portfolios
- Guiding PacifiCorp to an appropriate margin of resources over demand
- Providing flexibility to respond to market changes

Planning was Least Cost and Deterministic

At its inception and through much of its history, conventional utility resource planning concerned itself primarily with choices among alternative supply-side resources and demand-side measures. Those choices were typically compared according to their cost implications, emphasizing lowest system cost under a limited set of future growth assumptions. The environmental impacts of choices were also quantified, principally as mass of air emissions and sometimes through imputed externality costs or emission "adders". Typically, utilities developed non-integrated resource plans as if the utilities were isolated entities. In such analyses, utilities were assumed to build generation and implement demand-side measures to meet all of their future needs, while wholesale energy markets were largely relegated to the calculation of short-run balancing "off-system" sales and purchases, a component of electricity costs.

Planning Must Recognize Risks and Markets

This least-cost and deterministic planning was entirely consistent with most utilities' operating and development practices and reflected the state of the industry through its history. This after-the-fact treatment of the wholesale marketplace in resource planning is increasingly untenable for several reasons.

First, through overt public policy and emerging industry structure, the competitive marketplace has emerged as a primary source of new supply for utilities.

Second, the current state of policy and market structure still leaves substantial uncertainties in the marketplace. The 2000-2001 experience in western electricity markets amply demonstrated issues of supply reliability and extreme price volatility in the marketplace.

Third, gas-fired generation has emerged as the resource of choice for the U.S. electricity industry. The reliance on natural gas has grown to such an extent that the adequacy of supply and volatility in price for gas is the major contributor to supply adequacy and price volatility for electricity. Equally, the growth in electricity generation's demand for natural gas adds to price uncertainty and volatility for gas markets.

The sections below examine these marketplace issues and experiences. (For a more extensive discussion of the history of electricity industry regulation and the emerging structure of the industry, see Appendix A.)

GROWING PROMINENCE OF THE ENERGY MARKETPLACE

The electricity industry market environment changed greatly in the last several years. Evolving federal policy and many state regulatory initiatives are encouraging competitive markets and a growing independent supply sector. Many states are also experimenting with or instituting retail competition.[1]

Federal Regulation Directs Movement to Market

Over the last 10 years, the Federal Energy Regulatory Commission (FERC) has been the primary locus of federal policy developments for the electricity industry. The Energy Policy Act of 1992 set federal policy direction to encourage robust competition in wholesale electricity markets. Following its introduction of service unbundling and competitive forces to natural gas pipeline regulation, the FERC turned its attention to transmission with its Order 888 implementing open access. FERC's Order 2000 moved further in the direction of orienting transmission to serving a competitive electricity market by encouraging regional transmission organizations (RTOs). Most recently, with its July 2002 notice of proposed rulemaking on a standard market design (SMD), the FERC underscored its intentions to develop a competitive wholesale market and to clarify the rules under which markets should operate. With these regulatory initiatives, federal policy has encouraged new players to participate in wholesale electricity markets. At the same time the FERC has concluded that, where effective competitive markets operate, wholesale prices can be set by market forces rather than by traditional cost of service regulation. Similarly, since 1992 and FERC Order 636, prices for natural gas commodity and bulk natural gas transmission have been deregulated.

Merchant Generators and Power Marketers

In parallel to these policy and regulatory developments, a new electricity industry segment has evolved and grown to supply traditional utilities or load-serving entities. These non-utility

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[1] Energy Information Administration, "The Changing Structure of the Electric Power Industry 2000: An Update", DOE/EIA-0562(00), October, 2000.

suppliers include cogenerators, small electricity producers, independent electricity producers, merchant generators and power marketers. Power marketers and merchant generators, in particular, have gained prominence in recent years. Power marketers, who buy and sell electricity as independent intermediaries, grew their U.S. sales from 27 million MWh in 1995 to 2,700 million MWh in 1999. Merchant generators grew into the role of acquiring, developing and owning power plants and marketing their output, often on a speculative basis.

Growth of the merchant sector of the electricity industry and increasing public policy emphasis on a competitive supply sector throughout the 1990s led a number of states to question whether traditional utilities should continue to build or acquire new resources to meet their customers' needs. Some have suggested that, instead, utilities should procure new resources from a competitive wholesale market. This philosophy is supported by experience in other restructured industries where competitive markets encourage both innovation in services and lower long-run costs. In this spirit, some states encouraged or required utilities to rely on the marketplace, even going so far, as in the case of California, requiring incumbent utilities to divest generating assets. In Oregon, the adoption of restructuring legislation and rules requires the revenue requirement from any new generating resources to be based on market prices rather than the traditional rate-basing of costs .

New Risks for Traditional Utilities

Load-serving-entities including PacifiCorp are now subject to new risks. What if independent electricity producers do not build enough supply? For years, utilities in the Pacific Northwest (PNW) planned their new resource needs around the concept that there should be enough resource 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?

The potential for competitive supply markets to deliver innovation and lower costs is still being tested. However, given the fluid and evolving nature of wholesale markets, they potentially increase the risk of market price uncertainty and volatility. Recent experience in western wholesale markets underscores this risk.

RECENT EXPERIENCE IN THE WESTERN ENERGY MARKETPLACE

The Electricity Supply Crisis

The reality of new risks in the competitive marketplace became painfully clear in the WECC electricity crisis of 2000 and 2001. In the prior decade, little new generation had been installed in the region, in relation to demand growth. A severe shortage of supply became apparent in May 2000. Later in the year, a rare severe Westwide drought significantly reduced WECC hydrogeneration resources. With prices set by the market rather than by regulation based on cost of supply, wholesale electricity prices rose to unprecedented levels, perhaps in part due to alleged market manipulation. To compensate for the hydrogeneration energy shortage, inefficient gas-fired generation (normally not expected to run) was operated often around the clock. This occurred at the same time that natural gas markets were experiencing their own strains.

The Natural Gas Shortage

Natural gas prices nationwide rose dramatically in 2000, reaching record levels in early 2001 before receding in the summer. This extraordinary run-up was caused by several factors. Relatively stagnant gas production for several preceding years was masked by a series of mild winter heating seasons. This imbalance was brought to a head by healthy gas demand growth in 2000. The imbalance led to low levels of gas storage entering into the 2001 heating season. Storage resources quickly became strained by exceptionally cold weather in November and December. The time lag between higher gas prices and the increased drilling and production meant very high prices would endure through and beyond the heating season. Supplies and prices were strained even further during this time by pipeline constraints into and within California.

The skyrocketing prices for natural gas plus limited hydro generation forced up spot electricity prices in all western markets. In addition, many of the inefficient gas-fired generation resources did not have sufficient emissions credits to cover their operation. Further increasing the price of spot electricity, the shortage of credits caused the price for any available credits to skyrocket.

Meltdown of the California Market

California's market structure also took its toll on electricity markets entering 2001. Since retail prices for the two largest utilities in the state (Southern California Edison and Pacific Gas and Electric) were capped while their supply costs were skyrocketing, a severe cash drain occurred. Competitive suppliers demanded price premiums to compensate for increased credit risk. In addition, the utilities withheld payments to some of their suppliers under direct electricity supply contracts (such as Qualifying Facilities (QF)) to preserve cash. In the face of extraordinary natural gas prices and no income, many QFs shut down generation, exacerbating the resource shortfall.

Further Blow to PacifiCorp

For PacifiCorp, the impact of these events was compounded by an unusual extended forced outage of its 430 MW Hunter 1 unit beginning on November 24, 2000 in PacifiCorp's eastern control area. This outage left PacifiCorp in a position of having to purchase electricity from the market to make up for the lost generation at just the time that market prices were at their highest. Moreover, PacifiCorp's eastern control area has limited access to major market points in the western system due to transmission constraints to the south and west. This left PacifiCorp exposed to markets that were potentially higher cost and more volatile than prevalent elsewhere in the west due to an absence of depth and liquidity.

End of the Crisis

Electricity prices began to drop rapidly from their unprecedented highs in June 2001. The dominant factor was a series of orders aimed at mitigating the potential for market power and reining in runaway prices issued by the FERC, especially the Price Cap order of June 19, 2001.

Market fundamentals after June 19th, combined with a decline in the demand for electricity kept 2001 spot prices low as the cap held down forward prices. Demand declined significantly in 2001 compared to the previous year, due to the economic slowdown, substantial conservation efforts by utilities and their customers, the reaction to higher prices in consumption decisions, and a fortuitously mild summer. Similar factors also helped ease natural gas demand while gas production rebounded, combining to bring gas prices down dramatically. New generation resources coming on line in the western system also helped restore reserve margins. As a result of all of these factors, by the middle of summer 2001, prices had retreated to levels 10% or less of what had been expected only months earlier. The extreme natural gas and electricity price volatilities over this period are illustrated in Figures 1.1 and 1.2.

Figure 1.1 Electricity Price Volatility

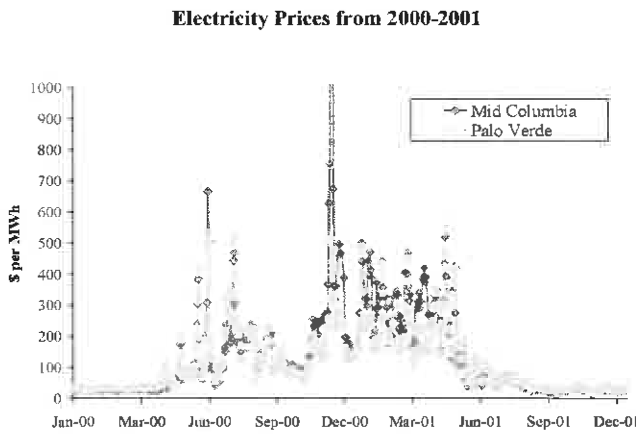
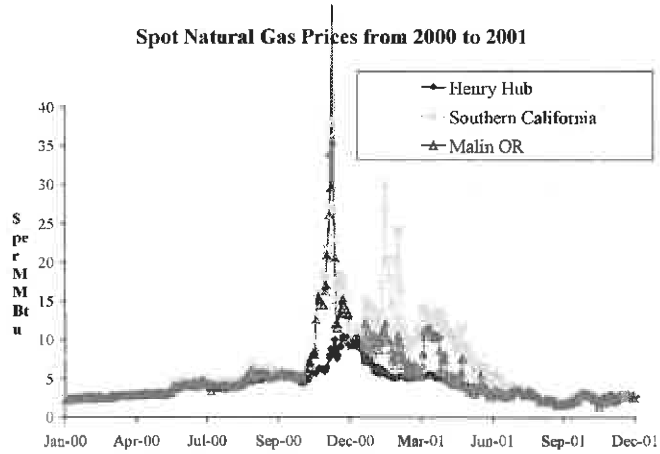


Figure 1.2 Natural Gas Price Volatility



Boom and Bust

Another aspect of uncertainty and volatility in electricity markets is portended by recent history in the WECC. The potential has emerged for a boom and bust cycle in electricity markets due to the cyclic addition of new generation. Between 1990 and 2000, less than 10,000 MW of new generating capacity was added to the WECC system. In contrast, more than 15,000 MW have been added in the 2000-2002 period, and an additional 16,000 MW of capacity are under construction in the WECC. Moreover, almost 95% of this new capacity is gas-fired. This wave of capacity additions is rapidly shifting WECC markets from a very tight (low reserve margin) to an over-supplied (high reserve margin) condition, probably for a number of years.

Two major consequences of this wave of new generation in the WECC are likely. First, electricity prices are expected to be depressed during the impending period of over-supply. Depressed prices discourage new construction and potentially set up another cycle of under- and over-supply. Second, gas-fired generation will now be the marginal resource and set spot market price in most peak hours. This ties WECC electricity prices inextricably to natural gas prices and their attendant uncertainty and volatility.

Retrenchment in Merchant Power

Another recent electricity market trend has arisen from the events described above. That trend is the remarkable retrenchment of the merchant electricity sector in the wake of the construction boom and wholesale electricity price volatility. As a result of an overhang of debt, credit problems, and other financial duress, a number of large energy merchants have reduced or eliminated their energy trading activities. Others have been forced to scale back their generation project developments, suspend construction, or dispose of assets. Lenders and rating agencies have recently questioned the entire merchant generation business model. This will reduce the depth and liquidity of energy commodity markets in the near term. In the long term it could impede the ability of existing merchant generators to provide additional generating capacity just as it impedes the entrance of new merchant generators. This decline of merchant generators underscores the need for capacity commitments from traditional utilities, either through longer-term forward contracts or their own resource development, and less exposure to volatile, short-term commodity markets to meet customers' needs.

NATURAL GAS SUPPLY ISSUES

North America is supplied by a large and diverse set of natural gas producers operating in a number of geographically dispersed producing regions tied together by an extensive pipeline network. As electricity generation increasingly relies on natural gas as a fuel, two issues deserve attention. First, declines in production from mature producing regions are forcing producers to turn to frontier regions for new supplies. This raises the prospect of an upward trend in natural gas costs. Second, the supply-and-demand dynamics of natural gas portend continued volatility in gas prices, especially when little spare production capacity is evident on the horizon.

Currently, mature producing areas (onshore and shallow water Gulf of Mexico and the mid-continent including the Permian Basin) account for about two-thirds of U.S. domestic gas production. Experience of the last five years demonstrates two factors that suggest growth in productive capacity from these areas should not be expected. First, drilling rig productivity (first year production per operating rig) is declining significantly. Second, the loss in annual deliverability from older wells is accelerating. Production in the Western Canadian sedimentary basin is beginning to exhibit these same tendencies.

Dynamics within the natural gas industry may cause the number of drilling rigs, production, investment, and prices to become more volatile[2]. The dynamics that increase the likelihood of volatile behavior include the responsiveness of supply and demand to changes in gas prices and the declining productivity of new wells.

Price Response in Natural Gas

In the short run, natural gas supply is fairly inelastic – in other words, the quantity supplied does not respond quickly to price changes. However, short-run demand is more responsive to changes in price and weather. The supply and demand dynamics and the ensuing abundance or scarcity

[2] For an in-depth discussion of this issue see "Potential for Cyclic Price and Investment Behavior" in Energy Information Administration, *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply*, SR/OIAF/2001-06, December 2001.

of production can lead to extreme fluctuations in short-run prices. Natural gas supply and demand has historically been more elastic in the long run. Therefore, large price fluctuations will eventually result in significant changes in consumption, producer cash flows and investment, and drilling activity. Typically, the delay between the onset of a price increase and the consequent increase in natural gas production is six to eighteen months. The average lag between a price decrease and the corresponding drop in production is seven months.

Declining Productivity

Declining production from new natural gas wells is an additional factor that impacts long-run price volatility. Between 1990 and 1999, the amount of time that passed before a well produced half its life time volume declined by 40%. Declining productivity and the consequent increase in drilling costs will leave investment and production more responsive to price changes. Incorporating random events into this potentially volatile market makes extreme fluctuations in price, investment and production more likely.

One firm, prominent in the analysis of natural gas markets, concludes the following from these trends:

On the supply side, the North American gas industry essentially can move in two directions. One would be to accelerate efforts to bring capital-intensive frontier gas resources into the market. Another would be to push forward the rapid expansion of liquefied natural gas (LNG). In either case, we envision a period when the North American gas industry will be hard-pressed to adjust domestic supply in a timely response to volatile shifts of demand. The past year's gas price spikes to $10 and below $2/MMBtu were no fluke, but instead they reflected this emerging supply/demand conflict[3].

FUTURE EMISSION COMPLIANCE ISSUES

Over the next decade, PacifiCorp faces a changing environment with regard to electricity plant emission regulations. The exact nature of these changes remains uncertain. Within the current federal political environment there exists a contentious debate over establishing a new energy policy and consequently, revising the Clean Air Act (CAA) to reduce overall emissions. Currently, the debate focuses on emission standards and compliance measures for sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), and carbon dioxide (CO_2). Several proposals to amend the Clean Air Act to limit air pollution emissions from the electric power industry are being discussed at the national level. A variety of existing and proposed requirements including multi-pollutant legislation, EPA's Regional Haze Rule, the Western Regional Air Partnership effort, and the Kyoto Protocol or alternative greenhouse gas emissions restrictions will further shape PacifiCorp's emission requirements over the coming decade.

Currently, PacifiCorp's generation units must comply with the Clean Air Act Amendments (CAAA) of 1990, which established standards for SO_2, and NO_x, and addressed a variety of toxic gasses. The CAAA also addressed PM_{10} (particulate matter smaller than 10 microns in size), but

[3] PIRA Energy Group, *North American Gas Market Outlook*, private retainer client report, March 19, 2002.

the standards have since been revised to include $PM_{2.5}$. Should standards under the current CAAA remain as is, future compliance costs would be relatively easy to estimate.

However, new federal proposals point to future changes. Specifically, proposed federal multi-pollutant legislation outlines changes in emission standards and compliance for SO_2, and NO_x, and establishes new definitive standards for mercury. The compliance costs associated with these future scenarios will largely depend on the levels of required reductions, the allowed compliance mechanisms, and the compliance time frame.

The Bush Administration's *Clear Skies Act (CSA)* is the less stringent of the legislative proposals, with a cap-and-trade system for SO_2, NO_x, and mercury and changes to new-source-review (NSR). CSA standards to reduce emissions would be established in two phases, starting in 2010 and 2018.

Senate Bill S. 556 (Clean Power Act), introduced by Senator Jeffords (I-VT*)*, is the more stringent proposed legislation, with lower annual emission caps for SO_2 and mercury than CSA, and an emission cap for CO_2. All caps would apply starting in 2008. CPA also utilizes a cap and trade system for all emissions except mercury.

The Clean Air Planning Act of 2002 introduced by Senators Carper (D-DE), Lincoln Chafee (R-RI), John Breaux (D-LA), and Max Baucus (D-MT) sets emission caps for SO2, NOx, Hg and CO2 that are more moderate than the Jeffords's proposal and more stringent than the President's CSA.

IMPLICATIONS OF MARKET DEVELOPMENT AND FUNDAMENTAL TRENDS

PacifiCorp and its customers are exposed to commodity markets that are likely to exhibit continued uncertainty and volatility. The uncertainty of future environmental costs and constraints also weigh heavily on future supply costs. Although the risks from exposure to these uncertainties cannot be eliminated entirely, prudent choice of new resources and the appropriate margin of resources in relation to demand can help to manage these risks.

One conclusion from the 2000-2001 market turmoil is that there is a clear asymmetry to market risks. On the high side, prices can increase rapidly under market shortage conditions, with limits set only by the perceived damage costs of shortages or by backstop caps set by regulation. Utilities with insufficient resources (those that are physically short electricity, in the parlance of commodity traders) are exposed to the risks of these spikes.

On the low price side, when markets have an overabundance of supply, wholesale market prices can fall not only below long-run replacement costs, but even below the short-run marginal cost of generation. Under these conditions, utilities or energy merchants who have excess of resources (have a long position) are exposed to the risk of not recovering their fixed costs in the market.

While significant, the low-side risk of a long position pales in comparison to the risk of a chronically short physical position. In general, neither an extremely long nor short position is desirable. A balanced position with sufficient planning margin so as to avoid physical short exposure to markets is prudent. While there is no silver bullet, as a prudently-run utility, PacifiCorp can manage the risk of commodity market exposure, in large measure, by planning and acting to maintain an adequate reserve margin. This broad conclusion is consistent with the FERC's Standard Market Design (SMD) proposal, which suggests that utilities be required to own or contract forward for resources sufficient to maintain an adequate planning reserve margin.

The exposure to fuel prices (for coal and natural gas) and environmental cost risks is no less complex. New gas-fired generation can help to mitigate future emission cost uncertainties, but exposes the supply portfolio to gas price volatility. New coal-fired generation avoids the fuel price volatility of gas but further exposes the supply portfolio to emission cost risks. Both demand-side management and renewable resources can avoid emission and fuel price exposures, but it is not clear how much of PacifiCorp's future resource requirements can be met from these sources.

There are no simple answers to these aspects of PacifiCorp's complex business environment. At the same time, these trends and uncertainties do provide clear direction to PacifiCorp's integrated resource planning.

THE NEW IRP IMPERATIVES

Changes in the structure and regulation of the electricity industry require changes in the approach PacifiCorp takes to integrated resource planning. Given the potential for commodity markets (both gas and electric) to exhibit rapid price swings (volatility), alternative resource plans must be evaluated in terms of their exposure to price volatility, in addition to their long-run average costs. Furthermore, unpredictability in the future costs of new supply alternatives arising from gas price and emissions cost uncertainties must be recognized. Finally, the rapidly evolving structure of markets and their attendant risks demand a more timely and responsive process for keeping resource plans current. This plan represents PacifiCorp's efforts to adapt IRP to these new requirements.

Fortunately, the emerging electricity industry structure presents opportunities as well as risks. Over time, a deep and liquid market for electricity and transmission increases the opportunity to acquire resources with differing terms, structures, and points of delivery. Moreover, new products will be offered by market participants to hedge or manage risks.

These risks and opportunities place new demands on PacifiCorp's IRP methods and processes. The analytical approach behind this IRP moves towards addressing those demands. Improvements incorporated into this IRP include a simulation approach that allows the performance of resource portfolio alternatives to be compared over a number of possible future conditions. This methodology provides an examination of both the expected future costs and the risks of future outcomes. It also allows an examination of the tradeoff between cost and risk inherent in resource planning choices. This is in contrast to PacifiCorp's recent IRPs, in which a point-estimate optimization method was used to develop plans tuned to a few specific future cases. This IRP also emphasizes portfolios of resources, since a diverse portfolio is a well-known means of managing risks.

CONCLUSION

As described in this chapter, the competitive energy market presents PacifiCorp with the prospect of continued price volatility and risk, and significant uncertainty affecting future resources. Although the risks from exposure to these uncertainties cannot be eliminated, the IRP will help to identify and manage these risks through the choice of new resources and by guiding PacifiCorp to an appropriate margin of resources over demand. This Integrated Resource Plan provides analysis leading to a comprehensive portfolio and strategy for PacifiCorp supply acquisition that balances low cost with risk

2. CURRENT POSITION

OVERVIEW

The regulated PacifiCorp is divided into (1) the transmission company and (2) the generation, wholesale and distribution company. Functionally, the PacifiCorp integrated system is made up of three functional service components or sectors: generation, transmission, and distribution. The generation sector is the production arm of the business. The transmission sector can be thought of as the interstate highway system of the business; the large high voltage lines that deliver electricity from electricity plants to local areas. The distribution sector can be thought of as the local delivery system; the relatively low voltage electricity lines that bring electricity to homes and businesses, constituting loads.

PacifiCorp forecasts load on its system to grow by 2.2% in East and 2.0% in West per year, on average over the next 20 years. Given uncertainties of economic growth and other factors, this growth in PacifiCorp's load could vary between 1.4% and 3.4% over the forecast period (see Appendix C for more details.) In contrast, PacifiCorp's resources available to serve demand will likely diminish over time as plants retire, certain contracts expire, hydro facilities are subjected to relicensing conditions and thermal plants comply with more stringent emissions requirements. This creates an imbalance that is referred to herein as the "Gap". This Gap between loads and existing resources grows through time. The Gap is expected to be large and strategically important.

While the exact size of this Gap is uncertain, PacifiCorp expects it will require approximately 4,000 MW of new resources (see Chapter 5 for an overview of new resources alternatives) through 2013. Understanding the size and timing of the Gap, as well as the seasonal and hourly shape of existing loads and resources, will help PacifiCorp choose the best new resources to fill this need. Similarly, an understanding of the transmission limitations linking the East and West control areas, and the resource needs facing the two control areas will help the company understand how the Gap grows and its relative shape in both areas.

Service Territory

PacifiCorp serves approximately 1.5 million retail customers in service territories aggregating about 135,000 square miles in portions of six Western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The service area's diverse regional economies range from rural, agricultural, and mining areas to urban, manufacturing, and government service centers. No one segment of the economy dominates, which helps mitigate exposure to economic swings.

In the Eastern portion of the service area, Wyoming and Eastern Utah, the main industrial activities are mining: extracting coal, oil, natural gas, uranium, and oil shale. In the Western part of the service territory, mainly consisting of Oregon and southeastern Washington, the economy generally revolves around agriculture and manufacturing, with pulp and paper, lumber and wood products, food processing, high technology, and primary metals being the largest industrial sectors.

The geographical distribution of PacifiCorp's retail electric customers is Utah, 650,445; Oregon, 496,226; Wyoming, 120,676; Washington, 118,363; Idaho, 55,813; and California, 41,891.

Figure 2.1 PacifiCorp Service Area

PacifiCorp Retail Load

In fiscal year 2002, PacifiCorp sold 47,527 Gigawatt-hours (GWh) of electricity to retail consumers in its service territory. This included 19,611 GWh of sales to industrial loads, 13,810 GWh of sales to commercial loads, and 13,395 GWh of sales to residential loads. As a result of the geographically diverse area of operations, PacifiCorp's service territory has historically experienced complementary seasonal load patterns. In the Western portion, customer demand peaks in the winter months due to heating requirements. In the Eastern portion, customer demand peaks in the summer when irrigation and cooling systems are heavily used.

At the current time, no single retail customer accounts for more than 1.4% of PacifiCorp's retail utility revenues and the 20 largest retail customers account for 13.8% of total retail electric revenues.

Wholesale Load

In fiscal year 2002, PacifiCorp sold 24,438 GWh of electricity to wholesale customers in the WECC. These sales included:

- Requirement sales
- Long term firm sales (greater than five year)
- Short term firm sales
- Long term unit contingent sales
- Non-firm sales

PacifiCorp has not included any new wholesale electricity sales in its load forecast. The regulated arm of PacifiCorp does not intend to build or acquire electricity supplies for the purpose of making new wholesale electricity sales. However, in the day-to-day operation of its electricity supplies against its retail load, PacifiCorp will make sales into (and purchases from) the broader WECC wholesale market as economics dictate.

RESOURCES

Demand Side Management (DSM) Programs

PacifiCorp has been operating DSM programs for many years. Following is a summary of these DSM program accomplishments for the last 10 years.

Previous PacifiCorp IRP (RAMPP - Resource & Market Planning Program) annual DSM system MWa goals acknowledged by the utility commissions have been regularly exceeded.

Table 2.1 Approved DSM Programs

Calendar Year	Goal MWa	Actual MWa	Actual Costs ($ MM)
1992	8.50	8.57	NA
1993	12.92	15.04	32.7
1994	15.29	20.79	34.3
1995	29.90	30.59	29.9
1996	23.09	24.11	16.5
1997	15.44	17.33	6.5
1999	9.00	12.19	7.2
1999	9.00	14.03	7.9
2000	9.00	6.27	9.6
2001	16.51	16.67	21.9

Table 2.2 DSM Programs Operating During 2002

DSM Program Name	Description	Availability (* programs under evaluation)
Energy FinAnswer (Schedule 125, enhanced with incentives)	Engineering & incentive package for improved energy efficiency in new construction and retrofit projects. Commercial, industrial, and irrigation.	OR, WA, UT
Lighting Retrofit Incentive (Schedule 116)	Incentives for energy-efficient lighting retrofit projects in commercial and industrial facilities greater than 20,000 sq. ft.	OR, WA, UT
Small Retrofit Incentive (Schedule 115)	Incentives for energy-efficient retrofit projects in commercial and industrial facilities less than 20,000 sq. ft.	OR, WA, UT
Energy FinAnswer (engineering and loan program; schedules vary by state)	Engineering & financing package for improved energy efficiency in new construction and retrofit projects. Commercial, industrial and irrigation.	WY, ID, CA
Appliance Recycling Program	An incentive program designed to remove inefficient refrigerators from the market.	ID*, UT*, WA*
Compact Fluorescent Light Bulb Program	Two free CFLs are offered to residential customers through direct mail offer. Provides immediate savings benefits and encourages CFL use.	ID*, WY*
Enhanced Audit and Weatherization Program	Residential In-home audit with customer choice of low interest loan or 25% rebate to assist in funding of cost effective recommended measures. Instant savings measures were added to legislatively mandated audit in mid-2000 in order to "enhance" the offer, improving cost effectiveness of program, providing for instant savings and increasing participation.	OR
Utah Residential and Small Commercial A/C Load Control Program	Turn-key load control network financed, built, operated and owned by a third party vendor through a pay-for-performance contract.	UT*
Low-Income Weatherization Program	The Company partners with community action agencies to provide no cost residential weatherization services to income qualifying households.	CA, ID, WA
Do-It-Yourself Home Audit	A residential fuel blind do-it-yourself home energy audit. Customers fill out the form and send it in, company generates a report of cost-effective recommendations and mails to customer.	CA, ID, OR, UT, WA, WY
Do-It-Yourself Web based audit	Residential and small commercial web based energy audit. Fill in the audit information and program provides an energy analysis of your home or business. Fuel blind audit.	Pilot in WA and possibly UT.
BPA Conservation and Renewable Discount Program	Credits received against our BPA electricity purchases for incremental energy efficiency and renewable investments. Strategy will be created on how best to leverage these dollars to best benefit the company and the communities we serve. About $2M annually through 2006.	OR*, WA*, ID*
Energy Efficiency Education – Bright Ideas Booklet	Published booklet featuring residential energy use and efficiency information that is mailed to customers upon request. Available in English and Spanish.	CA, ID, OR, UT, WA, WY
Low Income Energy Education Services	Provide qualifying customers energy education and do-it-yourself instruction on how to reduce energy costs and minimal direct install assistance to qualifying senior citizens.	OR – Portland Area only
Efficient Air Conditioning Program	Provide customer incentives for improving the efficiency of air conditioning equipment and/or maintaining or converting air conditioning equipment to evaporative cooling technologies.	UT*, WA*
Energy Education to Schools	Provide classroom instruction to grade school and intermediate students on energy education.	WA, Lower Yakima Valley Schools
Low Income Conservation	Energy education and conservation measure installation services to a minimum of 550 households annually over a 3 year period (beginning FY 2001). Estimated savings per home 1,636 KwH.	UT
Northwest Energy Efficiency Alliance (NEEA)	A series of conservation programs sponsored by utilities in the region designed to support market transformation of energy efficient products and services in OR, WA, ID. Programs include manufacturer rebates on compact fluorescent bulbs to building operator training courses	WA, ID

DSM Program Name	Description	Availability (* programs under evaluation)
Commercial Retro Commissioning	Pilot program designed to work with customers to re-commission the operation of their commercial buildings consistent with the building was designed to operate.	UT*

Supply Side Resources

PacifiCorp owns or has interests in generating plants with an aggregate plant net capability of 7,920 MW. With its present generating facilities, under average water conditions, approximately 6% of PacifiCorp's energy requirements for 2003 would be supplied by its hydroelectric plants, 66% by its thermal plants, and the balance of 28% would be obtained under long-term purchase contracts, exchange and other purchase arrangements.

Hydro

PacifiCorp's hydroelectric portfolio consists of 53 generating plants, with a capacity of 1,119 MW. Ninety-seven percent of the installed capacity is regulated by FERC through 20 individual licenses. These projects account for about 13% of PacifiCorp's total generating capacity and provide operational benefits such as peaking capacity, generation, spinning reserves and voltage control.

Nearly all of PacifiCorp's hydroelectric projects are in some stage of relicensing under the Federal Power Act (FPA). The relicensing process is a public regulatory process that involves controversial resource issues. In granting the new licenses, FERC is expected to impose conditions designed to address the impact of the projects on fish and other environmental concerns. In addition, under the FPA and other laws, the state and federal agencies and tribes have mandatory conditioning authorities that give them significant influence and control in the relicensing process. It is difficult to determine the economic impact of these mandates, but capital expenditures and operating costs are expected to increase in future periods while electricity losses may result due to environmental and fish concerns. As a result of these issues, for example, PacifiCorp has analyzed the costs and benefits of relicensing the Condit Dam and has agreed to remove the Condit Dam at a cost of approximately $17 million.

Thermal

PacifiCorp also owns or has interests in 18 thermal-electric generating plants with an aggregate nameplate rating of 7,289 MW and plant net capability of 6,769 MW.

During 2001 and 2002, PacifiCorp leased gas turbine peaking generators with 95 MW capacity to provide electric generation to meet load requirements in Utah. The Company has replaced these leased gas turbine peakers at its Gadsby Plant, in Salt Lake City, Utah, with 120 MW (three 40 MW units) Company-owned gas-fired turbines. The turbines went online in late summer 2002, and are included in the thermal-electric generating plant totals listed above.

Wind

PacifiCorp jointly owns one wind electricity generating plant at Foote Creek, Wyoming with a plant net capability of 33 MW. In addition, PacifiCorp has signed a 20-year agreement to purchase the entire output of the Rock River I wind electricity project located in Arlington, Wyoming, which has a net capacity of 50 MW. This project continues PacifiCorp's commitment to develop additional megawatts generated by renewable resources. Table 2.3 summarizes PacifiCorp's existing generating facilities.

Table 2.3 Existing Generation Facilities

HYDROELECTRIC PLANTS	**Location**	**Energy Source**	**Installation Dates**	**Nameplate Rating (MW)**	**Plant Net Capability (MW)**
Swift	Cougar, WA	Lewis River	1958	240.0	263.6
Merwin	Ariel, WA	Lewis River	1932-1958	135.0	144.0
Yale	Amboy, WA	Lewis River	1953	134.0	134.0
Five North Umpqua Plants	Toketee Falls, OR	N. Umpqua	1949-1956	133.5	137.5
John C. Boyle	Keno, OR	Klamath River	1958	80.0	84.0
Copco Nos. 1 and 2 Plants	Hornbrook, CA	Klamath River	1918-1925	47.0	54.5
Clearwater Nos. 1 and 2	Toketee Falls, OR	Clearwater	1953	41.0	41.0
Grace	Grace, ID	River	1914-1923	33.0	33.0
Prospect No. 2	Prospect, OR	Bear River	1928	32.0	36.0
Cutler	Collingston, UT	Rogue River	1927	30.0	29.1
Oneida	Preston, ID	Bear River	1915-1920	30.0	28.0
Iron Gate	Hornbrook, CA	Bear River	1962	18.0	19.5
Soda	Soda Springs, ID	Klamath River	1924	14.0	14.0
Fish Creek	Toketee Falls, OR	Bear River	1952	11.0	12.0
		Fish Creek			
33 Minor Hydroelectric Plants	Various	Various	1896-1990	89.3*	89.1*
SUBTOTAL (53 HYDROELECTRIC PLANTS)				**1,067.8**	**1,119.3**
THERMAL ELECTRIC PLANTS	**Location**	**Energy Source**	**Installation Dates**	**Nameplate Rating (MW)**	**Plant Net Capability (MW)**
Jim Bridger	Rock Springs, WY	Coal-Fired	1974-1979	1,541.1*	1,413.4*
Huntington	Huntington, UT	Coal-Fired	1974-1977	996.0	895.0
Dave Johnston	Glenrock, WY	Coal-Fired	1959-1972	816.8	762.0
Naughton	Kemmerer, WY	Coal-Fired	1963-1971	707.2	700.0
Hunter 1 and 2	Castle Dale, UT	Coal-Fired	1978-1980	727.9*	662.5*
Hunter 3	Castle Dale, UT	Coal-Fired	1983	495.6	460.0
Cholla Unit 4	Joseph City, AZ	Coal-Fired	1981	414.0*	380.0*
Wyodak	Gillette, WY	Coal-Fired	1978	289.7*	268.0*
Carbon	Castle Gate, UT	Coal-Fired	1954-1957	188.6	175.0
Craig 1 and 2	Craig, CO	Coal-Fired	1979-1980	172.1*	165.0*
Colstrip 3 and 4	Colstrip, MT	Coal-Fired	1984-1986	155.6*	144.0*
Hayden 1 and 2	Hayden, CO	Coal-Fired	1965-1976	81.3*	78.0*
Blundell	Milford, UT	Geothermal	1984	26.1	23.0
Gadsby	Salt Lake City, UT	Gas-Fired	1951-1955	251.6	235.0
Gadsby Peakers	Salt Lake City, UT	Gas-Fired	2002	120.0	120.0
Little Mountain	Ogden, UT	Gas-Fired	1971	16.0	236.0*
Hermiston	Hermiston, OR	Gas-Fired	1996	237.0*	52.0
James River	Camas, WA	Black Liquor	1996	52.2	
Subtotal (18 Thermal Electric Plants)				**7,288.8**	**6,768.9**
OTHER PLANTS	**Location**	**Energy Source**	**Installation Dates**	**Nameplate Rating (MW)**	**Plant Net Capability (MW)**
Foote Creek	Arlington, WY	Wind Turbines	1998	32.6*	32.6*
Subtotal (1 Other Plant)				32.6	32.6

Total Hydro, Thermal and Other Generating Facilities (72)		**8,389.2**	**7,920.8**

*Jointly owned plants; amount shown represents the Company's share only.

Fuel

As of March 31, 2002, PacifiCorp had 218 million tons of recoverable coal reserves that are mined by PacifiCorp or its affiliates. All coal reserves are dedicated to nearby generating plants operated by PacifiCorp. During 2002, these mines supplied approximately 32.5% of PacifiCorp's total coal requirements, compared to approximately 50% in 2001. The decline is due to the 2001 closure of the Trail Mountain Mine, which was no longer economically viable. Coal is also acquired through long-term and short-term contracts. It is deemed favorable to have a mix of purchased and mined coal supplies. Table 2.4 describes PacifiCorp's recoverable coal reserves as of March 31, 2001.

Table 2.4 PacifiCorp Coal Reserves

Location	Plant Served	Recoverable Tons (in millions)
Craig, Colorado	Craig	50[4]
Emery County, Utah	Huntington and Hunter	68[5]
Rock Springs, Wyoming	Jim Bridger	100[6]

The Company supplies its generation plants with the natural gas needed for operations through long-term and short-term contracts.

WHOLESALE SALES AND PURCHASED ELECTRICITY

PacifiCorp wholesale purchases and sales complement its retail business, form a critical part of its balancing and hedging strategy, and enhance the efficient use of its generating capacity.

Balancing and Hedging Strategy

PacifiCorp's primary business is to serve its retail customers. The Company's business is exposed to risks relating to, but not limited to, changes in certain commodity prices and counterparty performance. The Company enters into derivative instruments, including electricity, natural gas and coal forward, option and swap contracts, and weather contracts to manage its exposure to commodity price risk and ensure supply and thereby attempts to minimize variability in net power costs for customers. The Company has policies and procedures to manage risks inherent in these activities and a Risk Management Committee to monitor compliance with the Company's risk management policies and procedures.

The Risk Management Committee has limited the types of commodity instruments the Company may utilize to those relating to electricity, natural gas and coal commodities, and those

[4] These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware non-stock corporation operated on a cooperative basis in which PacifiCorp has an ownership interest of approximately 21.4%.
[5] These coal reserves are mined by subsidiaries of PacifiCorp and are in underground mines.
[6] These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc., a subsidiary of PacifiCorp, and a subsidiary of Idaho Power Company. Pacific Minerals, Inc. has a two-thirds interest in the joint venture.

instruments are used for hedging price fluctuations associated with the management of resources. The Company's hedging is done solely to help balance retail and wholesale load. Short-term commodity instruments are occasionally held by the Company for trading purposes.

Wholesale Sales and Purchases

Long-term electricity purchases supplied 11.8% of PacifiCorp's total energy requirements in 2002. Short-term and spot market electricity purchases supplied 20.5% of PacifiCorp's total energy requirements in 2002.

Historically, during the winter, PacifiCorp has been able to purchase electricity from utilities in the Southwestern United States, principally for its own peak requirements. The Company's transmission system connects with market hubs in the Pacific Northwest having access to low-cost hydroelectric generation and also with market hubs in California and the Southwestern United States with access to higher-cost, fossil-fuel generation. The transmission system is available for common use consistent with open access regulatory requirements. If PacifiCorp is in a surplus electricity position, PacifiCorp is able to sell excess electricity into the wholesale market.

In addition to its base of thermal and hydroelectric generation assets, PacifiCorp utilizes a mix of long-term, short-term and spot market purchases to meet its load obligations, wholesale obligations and its balancing requirements. Many of PacifiCorp's purchased electricity contracts have fixed-price components, providing protection against price volatility.

PacifiCorp currently purchases 925 MW of firm capacity annually from BPA pursuant to a long-term agreement. This purchase helps PacifiCorp to balance its thermal generation to loads by taking delivery during on-peak hours and make the required return of energy during off-peak hours. The purchase amount declines to 750 MW in July 2003 and again to 575 MW in July 2004 through August 2011. Can PC reverse this?

Under the requirements of the Public Utility Regulatory Policies Act of 1978, PacifiCorp purchases the output of qualifying facilities constructed and operated by entities that are not public utilities. During 2002, PacifiCorp purchased an average of 104 MW from qualifying facilities, compared to an average of 109 MW in 2001.

PacifiCorp also has commitments to purchase electricity from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project annual costs (operating expenses and debt service). These costs are included in operations expense. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. For 2002, such purchases approximated 1.9% of energy requirements.

Under the hydroelectric purchases described above, PacifiCorp contracts for electricity from four dams located on the middle Columbia River. These four dams are currently licensed by FERC to three public utility districts (PUD) located in central Washington. Chelan County PUD has the FERC license for Rocky Reach Dam, Douglas County PUD has the license for Wells Dam, and Grant County PUD has the license for Priest Rapids and Wanapaum Dams. PacifiCorp's contracts with these PUDs generally terminate at the same time as the current FERC license expires.

In December 2001, PacifiCorp reached an agreement with Grant County PUD to renegotiate the Wanapum and Priest Rapids contracts after the current contracts expire. The terms and conditions of the new contracts will vary from terms and conditions currently in place.

Table 2.5 shows PacifiCorp's share of long-term arrangements with public utility districts as of March 31, 2002

Table 2.5 PacifiCorp Mid-Columbia Hydro Contracts

Generating Facility	Year Contract Expires	Capacity Winter (MW)	Percentage of Output (%)	Annual Costs[7](a)
Wanapum	2009	155	18.7	7.0
Priest Rapids	2005	110	13.9	4.0
Rocky Reach	2011	64	5.3	3.1
Wells	2018	60	6.9	2.0
Total		389		$16.1

In September 2001 PacifiCorp, through an independent third party, issued a Request for Proposals for electric supply that can be delivered into PacifiCorp's Utah Power electric service territory. This process resulted in a lease with PacifiCorp Power Marketing (PPM, PacifiCorp's unregulated wholesale power marketing affiliate) for new peaking resources in the Utah Power service territory and several contracts for peak electricity to be delivered into that territory. The costs associated with the leasing of a 200 MW natural gas-fired electricity plant from PPM (located in West Valley, UT) is subject to regulatory acceptance. The plant became operational in the summer of 2002, and is currently operating at its full capacity.

See Appendix C, Tables C.1, C.2, and C.3 for a complete listing of long-term purchase, sales and exchange contracts.

TRANSMISSION

PacifiCorp's transmission system is interconnected with more than 80 generating plants and 15 adjacent control areas at 124 interconnection points. PacifiCorp's transmission asset ownership has resulted in PacifiCorp's significant involvement in recent transmission industry changes. PacifiCorp has had an open access transmission tariff on file at the Federal Energy Regulatory Commission (FERC) since 1989. The PacifiCorp transmission business operates independently and markets its transmission services using an Open Access Same-time Information System (OASIS).

[7] Annual costs in millions of dollars. Includes debt service of $6.3 million. The Company's minimum debt service obligation at March 31, 2002 was $9.0 million, $9.0 million, $8.0 million, $10.0 million and $10.0 million for the years 2003 through 2007, respectively.

PacifiCorp operates two separate control areas, the West and the East. The Bridger Plant in Wyoming (with associated transmission through Idaho) is a dedicated Western resource. PacifiCorp has contractual rights to transfer up to 1,600 MW of electricity from the Bridger plant on Idaho Power Company's transmission lines to PacifiCorp transmission at the Midpoint substation in Idaho. These rights are unidirectional with the exception of 100 MW bi-directional allocated to reserves (RTSA). Other transmission that permits benefits from regional diversity includes PacifiCorp's share of the AMPS line[8]. Outside of these ownership rights and firm contracts, PacifiCorp has to pay for transmission wheeling and congestion costs to fully optimize use of its resources between East and West.

In the West, PacifiCorp territory is integrated with the BPA network. PacifiCorp uses network firm rights on the BPA transmission to cover its service territory and connect to markets. In the East, however, the PacifiCorp transmission system in Wyoming and Colorado is sufficient, though in Utah it is becoming congested.

Congestion refers to transmission paths that are constrained, imposing limited power transactions because of insufficient capacity. Congestion can be relieved by increasing generation, reinforcing transmission or by reducing load. The following are examples of congested paths that were encountered in the IRP planning:

- Constraints on the west of Bridger transmission system resulted in increased PVRR due to greater transmission integration costs, hence making the Wyoming coal option less attractive than Hunter #4
- The rating of WECC Path C, i.e., the lines between Utah and Idaho, limits transfer capability into the Utah bubble — path C at peak times . 10% of time > 75% of OTC
- West of the Cascade South congestion increases the integration cost for wind developments from an area considered to be one with the highest wind potential in the Northwest

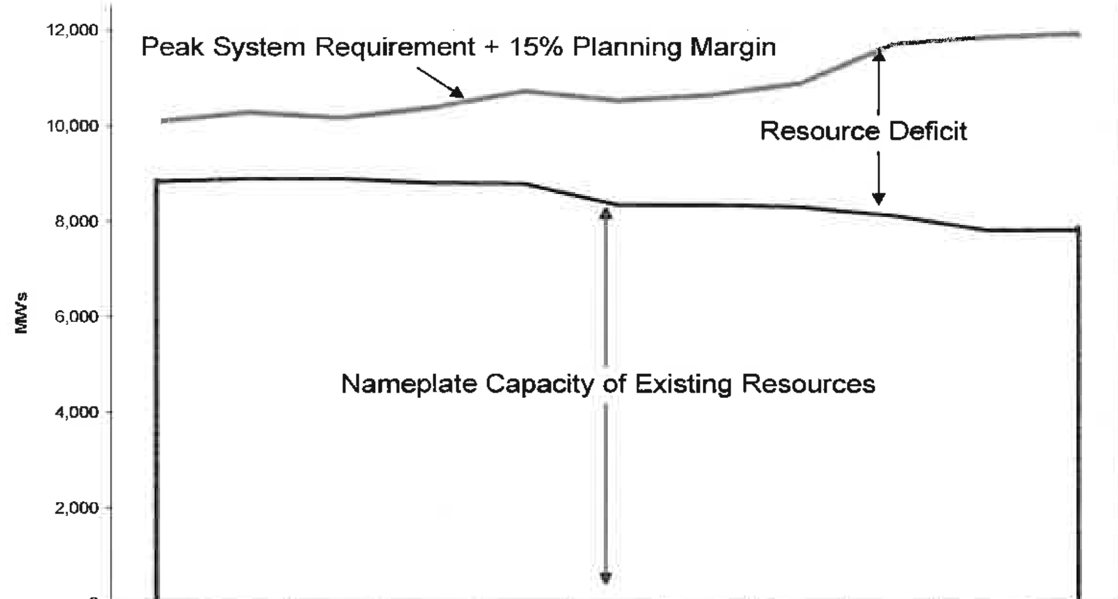
PacifiCorp's firm transmission rights must be analyzed with caution. At times, the sum of imports "available" according to stated contract rights do not equal the transfers physically available to the system. Such inequalities occur because transmission paths and system subsets operate in an interrelated manner. For example, transmission in and around Utah is particularly prone to inadvertent (or loop) flow. Inadvertent flows cause the simultaneous import capability into Utah to be significantly lower than the non-simultaneous limit. In other words, reaching the transfer limit on one path may concurrently diminish the transfer limits on other paths.

PACIFICORP POSITION -THE GAP

The difference between the load forecast and the existing PacifiCorp resources define the shortfall in supplies. Figure 2.2 provides an illustration of the peak system requirement with a 15% planning margin and the capacity of PacifiCorp's existing resources as they are expected to exist in the future.

[8] The Amps line is a 230 kV transmission line linking eastern Idaho with western Montana.

Figure 2.2 PacifiCorp System Capacity



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Pk Rqmt + 15%	10,090	10,288	10,176	10,379	10,731	10,531	10,641	10,893	11,712	11,869	11,936
Existing Capacity	8,833	8,894	8,893	8,800	8,788	8,335	8,335	8,299	8,119	7,820	7,820

Calendar Year

Note: Existing resources plotted above assume all long-term contracts are not renewed.

1257 1394 1283 1579 1743 2196 2306 2594 3593 4049 4116

DPI 1790 834 1458 1752 2406 3130 3394 3858 4932 5602

The annual peak system requirement can be defined as the hour of the year when the loads plus long-term firm sales minus long-term firm purchases results in the largest requirement on our system. The planning margin (15%) is the target reserve level assumed to provide sufficient future resources to cover forced outages, provide operating reserves and regulatory margin, and allow for demand growth uncertainty.

As mentioned earlier in this chapter, PacifiCorp operates in two control areas –West and East. These two control areas have very different resource and transmission issues, which results in a different balance in loads and resources for each side of the system.

Figures 2.3 and 2.4 represent the average net position for each month from April 2003 to March 2011, for both PacifiCorp West and East, respectively. Hourly net operating margins are included in the calculations of net position, and the values are shown after East-West transfers. The net position is shown for the Heavy Load Hour (HLH) and Light Load Hour (LLH) periods (see glossary for definition of HLH and LLH).

firm

Figure 2.3 PacifiCorp West Gap Analysis

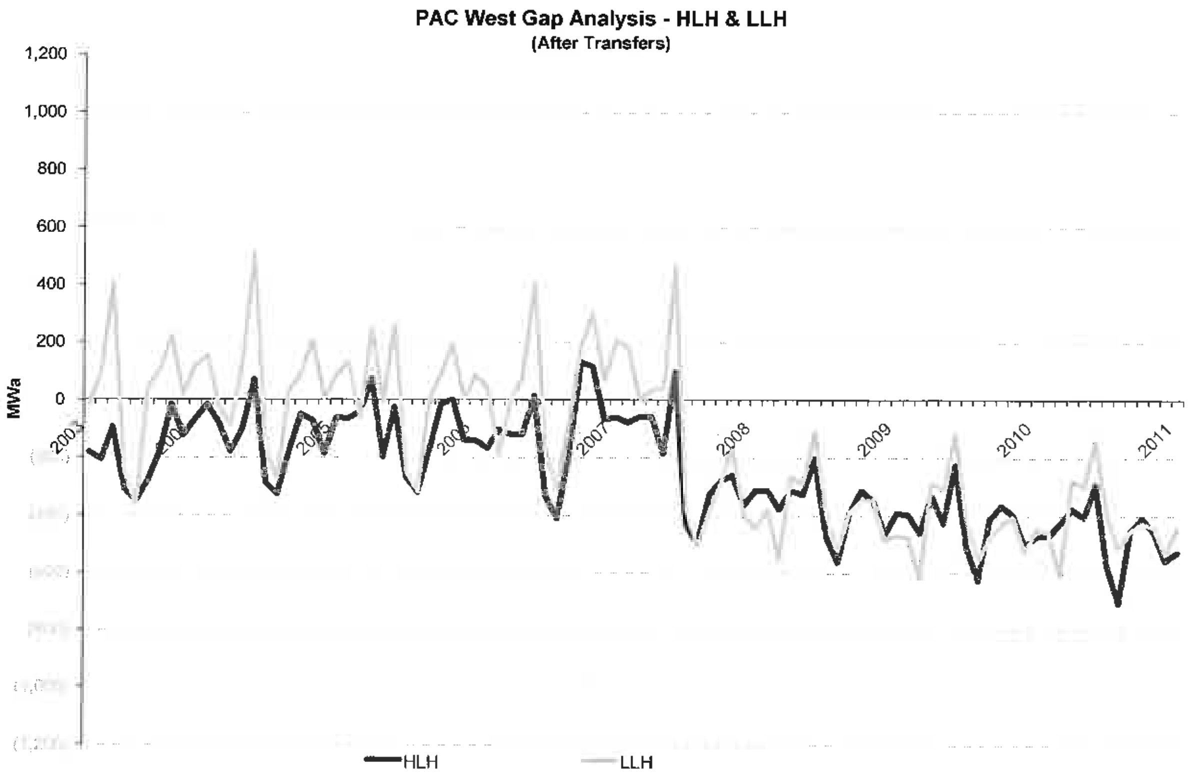
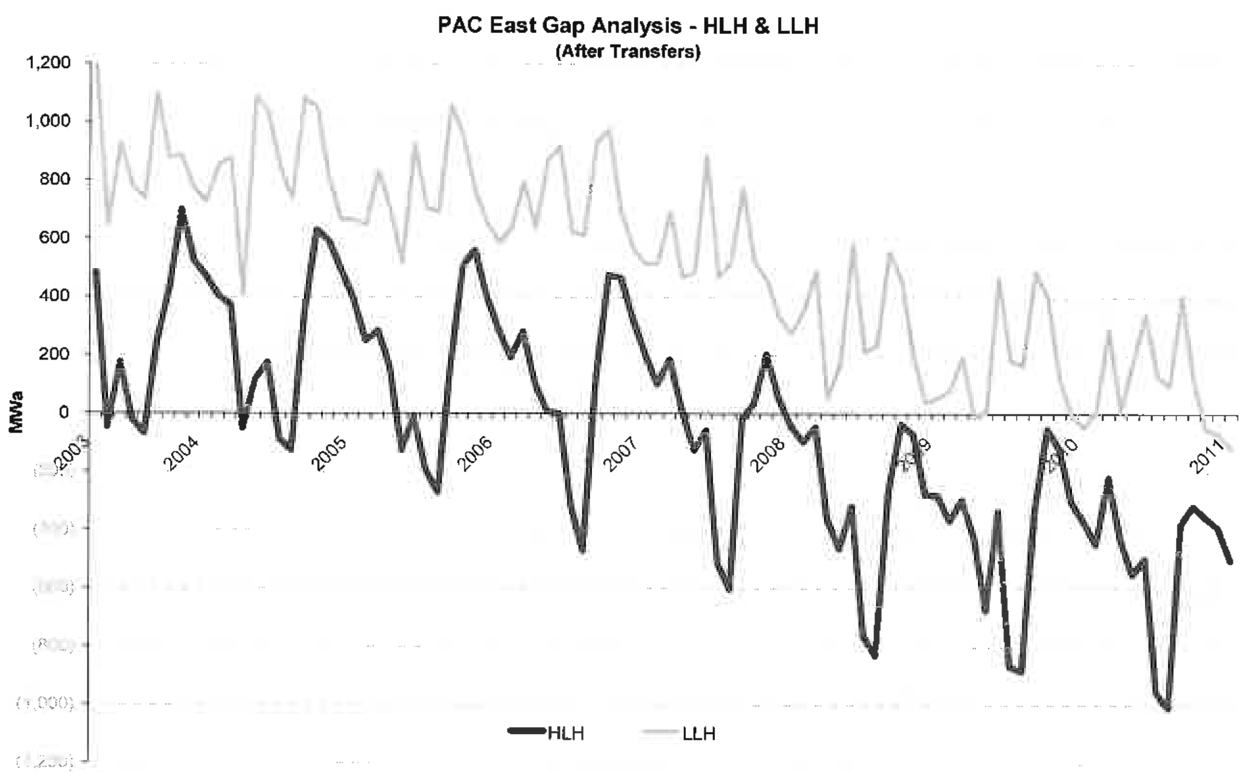


Figure 2.4 PacifiCorp East Gap Analysis



PacifiCorp West
The gap in PacifiCorp West is the result of a financial and an energy problem. The financial problem is caused by contract expirations and the uncertainty surrounding renegotiating these contracts at a favorable price. A significant impact of these expirations is felt as early as 2007 when a few large contracts such as Clark County and Transalta expire (see Appendix C for complete list of existing contracts). While the resources associated with these contracts remain, there is uncertainty around renegotiating the contract, and an inherent impact on new resource choices.

The energy problem in the West results from uncertainty around the energy that a hydro unit produces. While there is adequate hydro capacity, the energy can vary seasonally and with changing weather. Furthermore, hydroelectric generation makes up a very large percentage of the PacifiCorp portfolio of generation in the West. Therefore, when hydroelectric generation is particularly deficient, there is limited PacifiCorp-owned thermal capacity to provide sufficient output to serve energy needs. Explain BPA peaking contract

PacifiCorp East
at peak only
PacifiCorp East has a transmission problem and a need for additional capacity. These needs are interrelated. The East requires more physical resources to fulfill the obligation to serve load. Transmission constraints limit imports from out of area. This results in either a need to build or buy additional generation capacity to fulfill the load obligation, or to build or upgrade the transmission system to relieve congestion and allow addition generation to be brought into the East. How much of the time? SSG-WS Trans Flow Study shows UT lines not constrained much - power goes out in summer at So.

However, as one can see from Figure 2.4, the Gap occurs only in the heavy load hours, which results in a load-shaping problem in the East. Particularly in the Wasatch front, where the peak is growing faster than the load, a need is demonstrated for more flexible or peaking resources.

CONCLUSION

PacifiCorp has a complex service territory served by a large and diverse portfolio of resources. Linked by an enormous transmission network, the service territory covers broad and distant areas of the WECC. PacifiCorp's generation portfolio contains a wide array of coal and natural gas fired units as well as a large collection of flexible hydroelectric resources. Also, many contractual arrangements complement these resources. However, the combination alone is insufficient to meet the growing load obligation. To serve the gap, PacifiCorp's body of assets is supplemented by a large and complicated array of electricity purchase arrangements. The gap, as defined earlier, is net of long-term contracts and supplemented by short-term contracts.

The gap between load and resources is perhaps the most distinctive and important feature of PacifiCorp's current position. Similarly, resolving the gap economically and reliably plays the central role in PacifiCorp's planning process.

3. RISKS AND UNCERTAINTIES

INTRODUCTION

Electric utilities operate in an increasingly uncertain and volatile environment. The Western energy market conditions of 2000-2001 described in Chapter 1 graphically illustrate this. These recent events underscore the importance of risk management.

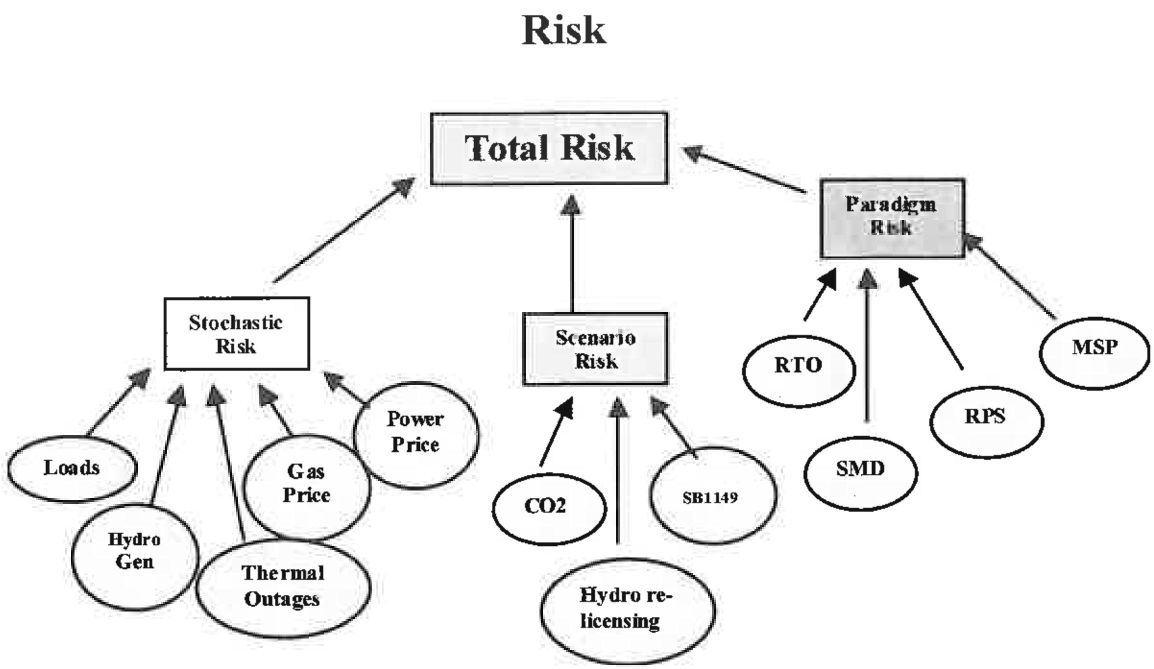
Clearly, every planning process should consider risk – that is, the possibility of different outcomes due to uncertainty about the future. However, general techniques for effectively incorporating risk analysis into utility resource plans have been more elusive. This Chapter discusses risk in general and describes the techniques PacifiCorp employed to incorporate risk analysis into its resource plan.

CLASSIFICATION OF RISK

Not all risks are assessed in the same way. For example, the Palo Verde electricity price realized next summer will most likely vary from expectations today (i.e., the forward price or a fundamental price forecast). This uncertainty and the associated impact can be quantified by applying stochastic modeling techniques described in Appendix H. However, if radical change is introduced in the way the electric utilities do business, e.g. Standard Market Design (or SMD), the model itself needs to be modified to account for the structural changes. Since the details of such radical changes are largely unknown, it is not possible at this time to quantify the related impact with mathematical modeling techniques.

Accordingly, the risks faced by PacifiCorp can be sorted into three general categories: Stochastic, Scenario and Paradigm risks. Scenario and Paradigm Risks constitute categories of what is frequently referred to as formal uncertainty. Figure 3.1 illustrates the categories of risk PacifiCorp faces.

Figure 3.1 Risk Diagram



Stochastic Risks

Stochastic risks are quantifiable risks. These parameters can be numerically represented and a known statistical process can be used to represent their variability.

Risks associated with business as usual variability typically falls within this category. PacifiCorp's analysis assumes that the Stochastic risk is driven by uncertainty in the following parameters (risk factors):

- Retail Loads (Northwest, Wyoming, Utah, Idaho)
- Spot Market Natural Gas Price (Mid Columbia, and two Utah nodes)
- Spot Market Electricity Price (Mid C, COB, PV)
- Hydrogeneration (PacifiCorp West, PacifiCorp East)
- Thermal Unit Availability

Explained by a known statistical process, Stochastic risks naturally lend themselves to simulation. As such, their variability is captured in the IRP's modeling and reported in Chapter 7. Refer to Appendix H for detailed information about the risk parameters above.

Scenario Risks

Scenario risks are also parameter driven. However the parameter variability cannot be reasonably represented by a known statistical process. This risk category is intended to embrace abrupt changes in the risk factors, such as introduction of high carbon allowance costs. The probability of high carbon allowance costs cannot be determined with a reasonable degree of accuracy. Therefore, a scenario of this occurrence is created without applying a probability to it. With assumed values (as opposed to simulated values) portfolios can be tested for their sensitivity to a specific Scenario risk.

Examples of Scenario risks addressed in the model are listed below. For a complete list of assumptions regarding these and other risk parameters, refer to Appendix C.

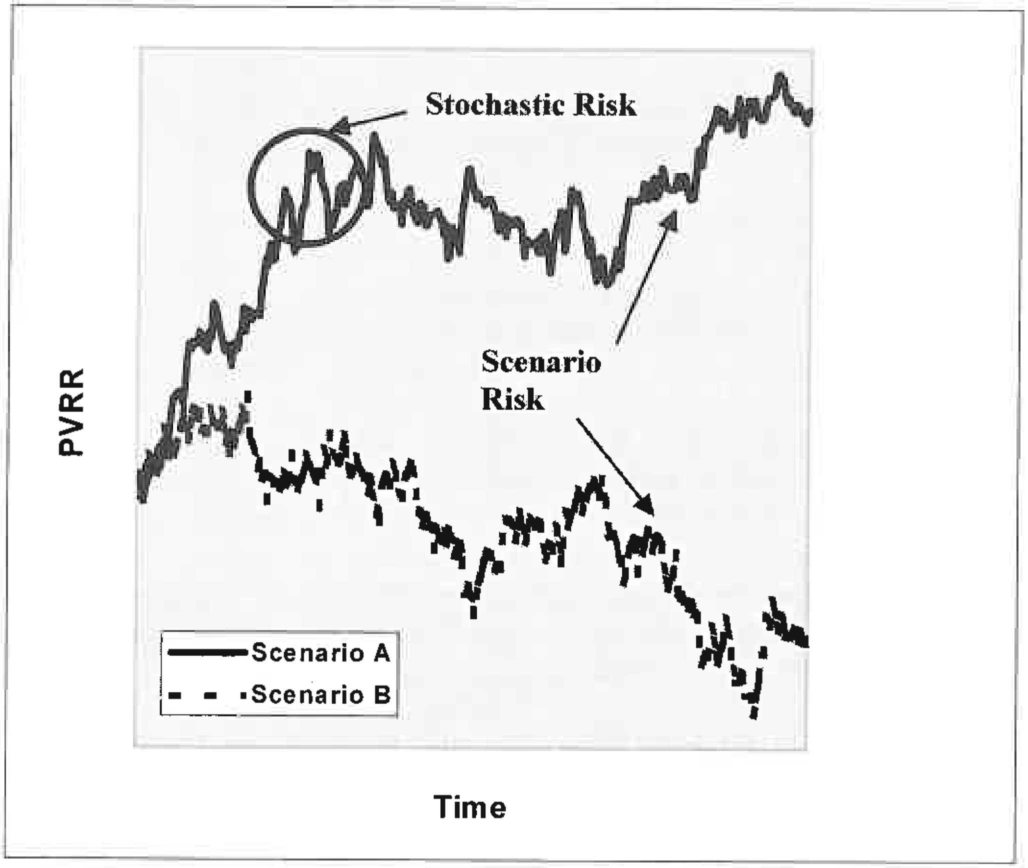
- Charges for prospective CO_2 emissions can be assigned. For example charges in the model are assumed to equal $8/ton above the year 2000 cap. Stress cases also modeled the impact of varying this allowance rate ($2/ton, $25/ton and $40/ton).
- Hydrogeneration relicensing efforts could affect future hydrogeneration capacity and energy levels. Adjusting expected energy output and stressing the capacity availability could assess the impact of this risk.
- The market value of Green Tags is influenced by the unknown probability of the passage of Federal and/or State renewable portfolio standards. However, Green Tags can be assumed to have an explicit value. For example a $5/MWh value was assigned for green tags.
- Renewable production tax credits are easily represented as a measurable economic subsidy to green generation because the value of the credit is provided by all tax payers. The probability of their extension is unknown. Therefore, modeling the parameter requires applying assumed values for the credit.

In the case of changing Scenario risks, the time evolution of Present Value Revenue Requirement (PVRR) takes a distinctly different path, rather than fluctuating around an expected value. The measure of Scenario risk is the difference between the expected PVRRs generated by applying different scenarios. The Figure 3.2, below, illustrates the different impacts of Stochastic and Scenario risks on a hypothetical series of annual revenue requirements.

Stochastic risks by definition vary randomly given a specific set of core assumptions for the Scenario Risks. We see the solid line jaggedly moving through time demonstrating a random (stochastic) series of outcomes.

Initially, the dashed and solid lines follow a similar path. However, the line shifts with the introduction of a change in a Scenario risk. For example, assume carbon allowance costs fall to $2/ton from $40/ton. The dashed line illustrates the shift (or shock) associated with a change in this Scenario risk assumption. The Scenario risk parameter is manually modified in order to observe the impact on the model. This is a form of stress testing.

Figure 3.2 Stochastic and Scenario Risk Illustration



Paradigm Risks

Paradigm risks cannot be reasonably represented by a number. Accordingly, the variability of Paradigm risks cannot be represented by a known statistical process. Paradigm risks are typically associated with large shifts in market structure or business practices, such as introduction of RTO West and SMD. Such innovations involve radical changes in the business model. Since the details of such changes are not presently specified, Paradigm risks do not easily lend themselves to quantitative analysis. The radical changes to fundamentals generally defy reasonable approaches to numerical representation until they are more fully specified.

While not explicitly modeled, Paradigm risks cannot be ignored. Accordingly, Paradigm risks are typically addressed outside of the model and cannot be summarized by a simple series of metrics. The assessment of Paradigm risks is usually qualitative rather than quantitative. Attempts, described below, are made to create a plan with the flexibility to respond to changes in Paradigm risks. In some instances, assumptions are explicitly modeled to impute additional flexibility. Despite these efforts, Paradigm risks, as they arise, will ultimately require a well reasoned response developed in conjunction with PacifiCorp, its regulators and the public.

DISCUSSION OF SPECIFIC RISKS

A large number of critically important Scenario and Paradigm risks currently fill the market. Each has the ability to dramatically affect PacifiCorp's operation. These risks merit additional discussion and include:

- Regional Transmission Organization and FERC's proposed Standard Market Design (RTO and SMD)
- Comprehensive Air Strategy
- Hydrogeneration Relicensing
- Renewable Portfolio Standard
- Multi-State Process
- Oregon Electric Restructuring (SB1149)

The information below provides background information on each risk. It also describes how the resolution of the risks could affect PacifiCorp and how the risks are analyzed within this IRP.

RTO and SMD

PacifiCorp, in conjunction with nine other utilities, is seeking to form a Regional Transmission Organization ("RTO West"), in response to FERC Order 2000. The 10 members ("filing utilities") of RTO West would be:

Avista Corporation	Nevada Power Company
British Columbia Hydro Power Authority	PacifiCorp
Bonneville Power Administration	Portland General Electric Company
Idaho Power Company	Puget Sound Energy, Inc
NorthWestern Energy LLC	Sierra Pacific Power Company

Creation of RTO West is subject to regulatory approvals from the FERC. Some of the states served by the filing utilities may also assert jurisdiction over certain matters relating to the formation of RTO West. RTO West, when fully implemented, will operate transmission facilities needed for bulk power transfers and control the majority of the 60,000 miles of transmission lines owned by the entities.

On July 31, 2002, the FERC issued its Notice of Proposed Rulemaking ("NOPR"), proposing a new Standard Market Design (SMD) for wholesale electricity markets and requesting comments from market participants. Comments are due in mid-November or mid-January, depending on the subject.

On September 18, 2002, the FERC Commissioners voted that, with some modification and further development of certain details, and the RTO West proposal not only satisfies the 12 characteristics and functions of Order 2000, but also provides a basic framework for standard market design for the West.

Going forward, the focus of the RTO project will be on completing the RTO West design details, influencing the final SMD Western market design framework. The filing utilities also plan to submit a proposed RTO West tariff in early 2003. In addition, the filing utilities have entered into a Memorandum of Understanding with the other two potential Western RTOs, namely WestConnect and California Independent Grid Operator and will work on inter-regional issues through that forum.

Potential Impact

Resource adequacy has been addressed in both the RTO West Order and the SMD NOPR. Within the SMD NOPR, FERC proposes that all Load Serving Entities must meet a minimum capacity reserve planning margin (12%) or face potential penalties. The required reserve margin could be set higher by a Regional State Advisory Committee, proposed by the SMD NOPR to advise the independent transmission provider. In contrast, the RTO West Order is more flexible in that it encourages the filers to consider reliability based development of a resource adequacy plan.

If a generation adequacy standard is imposed on PacifiCorp, either through the SMD requirement or as a consequence of a future standard adopted by the RTO West, the impact on PacifiCorp's IRP process could be both direct and indirect. Directly, PacifiCorp could be required to make generation additions or enter into firm contracts to meet a minimum Planning Reserve Margin. If the Planning Reserve Margin were set too high, PacifiCorp and its customers would incur unnecessarily high costs without reliability or risk reducing benefits. Since the same requirement would impact all other load serving entities in the WECC, it could be expected to impact the supply-demand balance throughout the WECC. This would indirectly affect PacifiCorp's system through its impacts on market prices throughout the WECC. The impact could be seen through a smoothing of boom-bust cycles of generation additions and market prices, an intended impact of the SMD. This impact could result in chronically low market prices and could potentially impact overall depth and liquidity of electricity markets.

Treatment in the IRP Models

The ultimate reserve requirements of SMD are unknown. Planning Margin discussions range from 12% to 18%. A 15% Planning Reserve Margin was assumed as a reasonable proxy for final SMD requirements. A 10% Planning Margin requirement was also analyzed as a stress to test the risk of a divergence from this assumption. Forecasts of future market prices were developed assuming that future resources would be added to the WECC to maintain a 16% reserve margin, on average.

RTO could impact the economics by which transmission rights are procured and energy flows. The risk of this change was addressed with a conservative bias. Accordingly, only firm transmission rights were modeled.

Comprehensive Air Strategy

PacifiCorp's coal-fired plants must comply with numerous, complex environmental air quality laws and regulations, some of which are the subject of industry-wide enforcement initiatives. In addition, new emissions requirements are expected to emerge over the next several years that will impose even more stringent pollution control requirements. PacifiCorp is the single biggest coal-fired power producer in the Western energy market. Therefore, existing and expected future emissions regulations create significant uncertainty for the future operations and investment requirements of PacifiCorp.

Air emissions are regulated under both federal and state law. The Environmental Protection Agency (EPA) oversees federal laws although most states, including Utah and Wyoming, have authority to administer the federal laws within their borders subject to EPA's oversight. At times, federal and state laws can overlap or seemingly be in conflict.

The primary pollutants of concern for coal-fired plants include: sulfur dioxide (SO_2), nitrous oxide (NO_x), particulate matter (PM), carbon dioxide (CO_2) and mercury (Hg). The environmental impact of these pollutants differs in the western and eastern part of the United States, with SO_2 being the biggest concern in the west and NO_x the largest concern in the east. The Administration's Clear Skies proposal recognizes that the West faces different air quality issues than other parts of the country and would set emission caps to account for these differences.

Coal-fired plants in general face future regulatory uncertainty due to a number of regulatory tools used by both government and private citizen groups to require further emission reductions. These methods include: (1) the New Source Review (NSR) enforcement initiative (see explanation below); (2) NSR rule changes; (3) visibility requirements; (4) ongoing compliance issues; (5) emerging new emission requirements, including new legislation; and (6) changing federal, state and public attitudes, including an increase in lawsuits by citizen groups to achieve emissions reductions. The most pressing of these is the NSR enforcement initiative which involves an attempt by the U.S. Environmental Protection Agency (EPA) to force emission reductions from coal fired powerplants through enforcement activities. These enforcement activities have included Notices of Violations (NOVs), civil complaints and similar actions against eight utilities and one federal agency in the eastern US along with the investigation of countless other coal plants across the country, including four PacifiCorp plants.

New Source Review (NSR)
The NSR program in general requires utility owners or operators to undertake NSR review and obtain a new permit if they propose to build new generating units or modify existing plants in a way that increases emissions of regulated pollutants. EPA's current interpretation of these rules has created substantial legal controversy and has resulted in EPA launching the NSR enforcement initiative.

Climate Change
Some compliance costs – like those associated with pollution control equipment for SO_2 and NOx – can more easily be predicted based on current and expected rules. However, other compliance costs are far less easily predicted or quantified. Most notable among these uncertain costs are costs associated with compliance with future climate change requirements regulating emissions of greenhouse gases. Determining the impact of potential carbon regulations poses a challenge due to the tremendous amount of uncertainty surrounding such a policy. This uncertainty includes the stringency of potential future regulations; the timing of these regulations; and the way in which they will be implemented – including the flexibility to trade emission allowances across sectors and countries.

Climate change policies are developing as a complex mix of requirements debated on both the international stage and through domestic policy developments.

Multi-pollutant Legislation

Several national proposals to amend the Clean Air Act to limit air pollution emissions from the electric power industry are being discussed at the national level. The three most prominent are:

- President Bush's Clear Skies Act/Global Climate Change Initiatives,
- Clean Power Act (S. 556) introduced by Senator Jeffords (I-Vt.), and
- The Clean Air Planning Act of 2002 (S.) introduced by Senators Carper (D-DE), Lincoln Chafee (R-RI), John Breaux (D-LA), and Max Baucus (D-MT).

The Administration's Clear Skies Act (H.R. 5266 and S.B. 2815), which was introduced by Reps. Barton (R-TX), Tauzin (R-LA) and Sen. Robert Smith (R-NH), requires reductions for SO_2, NOx and Hg. Implemented through a tradeable allowance program, the emissions caps would be imposed in two phases: 2008 and 2019. The Administration proposal recognizes that the east faces different air quality issues than other parts of the country and will set emission caps to account for theses differences. The second Bush Administration proposal (for which no legislation has been introduced) initiates a new voluntary greenhouse gas reduction program. The plan focuses on improving the carbon efficiency of the economy, reducing current emissions of 183 metric tons per million dollars of GDP to 151 metric tons per million dollars of GDP by 2012. The Administration's proposal relies on various voluntary programs and incentives to encourage reductions in greenhouse gases from diverse sources, including CO2 from electric generation.

The Carper bill would regulate SO_2, NOx, mercury and CO_2 emissions from the electric generating sector: (1) the SO_2 mandate would reduce emissions via three phases to 2.25 million tons in 2015; (2) the 2-phase NOx program culminates with a 2012 cap of 1.7 million tons; (3) the mercury cap would be in two phases: 2008 and 2012; (4) the two-phase CO_2 program would cap emissions at 2005 levels in 2008 and 2001 levels in 2012.

The Jeffords bill (S. B. 556), the most stringent of the bills, requires power plants to reduce sulfur dioxide and nitrogen oxide emissions by 75 percent, mercury emissions by 90 percent and carbon dioxide to 1990 levels, all by 2008.

Mercury Maximum Achievable Control Technology (MACT)

Mercury (Hg) controls are also being considered separately from multipollutant legislation under the Maximum Achievable Control Technology (MACT) standards under the CAA (Clean Air Act). In December 2000, EPA determined that Hg emissions must be regulated. EPA is under a court-approved consent decree to propose a rule establishing MACT standards for Hg for coal-fired power plants by December 2003 and to finalize that rule by December 2004. Power plant operators must comply with the rule by December 2007.

Mercury control options are highly dependent on the chemical form and concentration of mercury in the coal and the fuel's chlorine content. These parameters may be tied to the type of coal used. Western bituminous coals have characteristics that are closer to sub-bituminous coals than to eastern bituminous coals. Sub-bituminous and western bituminous are generally harder to control than eastern bituminous coal.

Further analysis of existing data and the collection of new data would potentially lead to a better understanding of the relationship between Hg emissions and an array of likely contributing factors including the chemical and physical characteristics of the coal, boiler technologies, control technologies, and stack parameters.

Approach

The company believes that improved environmental quality can be achieved by taking leadership positions in these arenas, but it must work with utility rate commissions to achieve alignment between environmental policies and allowable expenses.

Potential Impact

The cost of meeting present, pending and future SO_2, NOx and Hg regulations will be substantial, with related after-tax OMAG and capital expenditures through 2025 ranging between \$500 million (NPV) and \$1.7 billion (NPV). The \$500 million represents a scenario in which SO_2 scrubbers and low-oxides of nitrogen burners (low-NO_x burners) are installed on PacifiCorp-operated units. The \$1.7 billion represents full controls (SO_2 scrubbers, Selective Catalytic Reduction controls for NO_x, and baghouses with activated carbon injection for mercury)

Capital costs for an SO_2 scrubber range from \$150 to \$330 per kW; baghouses \$60 to \$130 per kW; low-NO_x burners \$15 to \$30 per kW; and Selective Catalytic Reduction controls for NO_x at \$100 to \$220 per kW. Other additional costs include fixed and variable O&M, as well as lost generation costs associated with installation and lower capacity.

Costs associated with potential future CO_2 requirements are not included in the above scenarios.

PacifiCorp Approach to Air Quality Standards

PacifiCorp is advocating a comprehensive approach to meeting various air quality standards. The plan would yield significant air quality improvements, a safe, reliable and cost effective energy supply, meet the company's commitment under the WRAP sulfur dioxide emission reduction curve, and integrate necessary improvements in air quality equipment with other efficiency and equipment replacement schedules at the coal facilities. The approach would give PacifiCorp the ability to integrate air quality concerns and expenditures into the overall Integrated Resource Plan (IRP) with improved certainty.

Treatment in the Model

- PacifiCorp's comprehensive approach to addressing air issues was not explicitly assigned a cost. Costs associated with this approach are common to all portfolios. It assumes existing plants run for their expected lives with assumptions for emissions reductions resulting from installation of new control technologies.
- PacifiCorp included CO_2 emission "adders" for the purposes of stress testing. The base case assumption is for a CO_2 tax of \$8/ton charged for each ton above year 2000 level emissions and credited if below the cap beginning in fiscal year 2009. Additional stresses were done

with \$2, \$25, and \$40/ton scenarios representing various possible policy outcomes with varying implementation dates and cap levels.

- SO_2 and NO_x emission restrictions impact portfolio cost by assessing a \$/ton charge for emissions above their cap or paying credit below the cap. Representative charges, based on PIRA estimates, are modeled.

Hydro Generation-Relicensing

Like the CAI, the issues involved in relicensing hydrogeneration facilities are complex. They involve numerous federal environmental laws and regulations.

PacifiCorp's hydrogeneration portfolio is 1,100 MW, generated at 54 facilities with 20 individual Federal Energy Regulatory Commission (FERC) licenses in six states. Hydrogeneration facilities account for about ten percent of PacifiCorp's overall generation portfolio and provide a critical resource to meet peak demands. The current hydrogeneration relicensing schedule with FERC extends to 2013.

FERC hydrogeneration relicensing is a very complex regulatory environment and is an extremely political and public process involving complicated and controversial public policy issues. Litigation is prevalent. There is only one alternative to relicensing, that being decommissioning. Both choices are expensive.

Under the Federal Power Act that governs the FERC process, fish and wildlife, cultural, recreational, land-use and aesthetics all are considered equal to energy production when considering relicensing. Since the responsible agencies place mandatory conditions in the license, FERC is not in a position to balance the requests between different agencies. For example, on a single-project relicensing, issuance of a water quality certification (referred to as a "401 certification" due to its placement in the Clean Water Act) is completed by the following agencies:

- Washington State Department of Ecology,
- National Marine Fisheries Services,
- U.S. Fish and Wildlife Agency (which prescribes fishway conditions),
- U.S. Forest Service
- Indian Nations (which prescribe measures if the project includes reservation lands).

These different requirements may not align. In addition, more federal, state and local regulations may apply. These include provisions of the Clean Water Act, Northwest Forest Plan, consultation under the Endangered Species Act, and state and federal fish recovery plans.

Potential Impact

Relicensing hydrogeneration facilities is costly. To date, relicensing has resulted in \$75m of accumulated costs that are anticipated to be added to the rate base when the generating facilities receive a new operating license. An additional \$60 million is expected to be spent over the next 10 years for this process. Costs related to the requirements of relicensing are expected to total \$1.5 billion to \$2.2 billion over the next 30 to 35 years. About 90 percent of the cost relates to the three largest projects Lewis River, Klamath River and North Umpqua, and nearly half of these costs are attributed to lost generation.

PacifiCorp's Approach to Hydrogeneration Relicensing

PacifiCorp is managing this process by attempting negotiated settlements as part of the relicensing process. PacifiCorp believes this proactive approach is the best way to achieve environmental improvement while managing costs. PacifiCorp is prepared to consider project decommissioning if that appears to offer the lowest-cost alternative for our customers. Finding ways to engage a larger public interest voice in these licensing projects would be helpful. Reforming the Federal Power Act to allow mitigation alternatives to agency mandates also is a priority.

Treatment in the IRP Model

- The model assumes a loss of energy due to operational changes and increased bypass flows in the base case for all portfolios. Future impacts are highly speculative at this time due to ongoing negotiations.
- The costs of relicensing projects are not included in the model analysis since they are common to all portfolios.
- Relicensing involves the risk (however remote) of a loss of capacity. Accordingly, a stress case was run to test the impact of losing just over 200 MW of hydrogenation capacity, or 20% of our hydrogenation portfolio.

Renewable Portfolio Standard (RPS)

The RPS examined in many of the modeling runs was based upon the version passed by the U.S. Senate in S. 517, which was the Senate's version of the federal Energy Bill in the 2001-2002 session. With the mid-term elections, it appears unlikely that the energy legislation adopting a federal RPS will be passed in the 2003 – 2004 session. The bill was the product of substantial negotiation and may indicate the form of a future federal RPS in the long-term. While discussion may stall on Capitol Hill, 13 states have passed a RPS, including Texas, California and Nevada. Other states, such as Utah and Washington, are contemplating an RPS in their 2003 legislative sessions.

The Senate version requires 1% of investor-owned utilities' electricity to come from non-hydrogeneration renewables, with the requirement rising by adding 0.6% each year to reach 10% in 2020.

The annual targets are lowered by rewarding retail electricity suppliers for existing hydrogeneration and renewables generation. Both existing hydrogeneration and renewables count towards reducing the load to which the percentage is applied. Existing renewables further count as a portion of the actual electricity generated to meet the standard. In addition, there is a 1.5 cent/kWh price cap on the premium cost above non-renewable electricity. These provisions will lower the explicit numerical targets of the bill—one recent study finds that the standard results in renewables representing just 6.5% of electricity supplied in 2020.

Based on PacifiCorp's estimates, which include the Senate's treatment of existing renewables and hydrogeneration, but do not include the 1.5 cent/kWh price cap, the current federal RPS proposal would result in PacifiCorp building or buying 20 new MWa of renewables by 2005. The target rises every year thereafter to 229 MWa by 2010 and 829 MWa by 2020.

Potential Impact
Early modeling runs featuring the RPS considered early adoption of renewables for numerous strategic and economic reasons.

With the renewables totals in the portfolio, PacifiCorp could be well positioned for future federal RPS. The Senate proposal provided full credit for existing renewables. Such legislation in the future would provide full regulatory risk reduction benefits to the renewables component of the portfolio.

Implementation of a renewables procurement strategy before broader sectoral demand "runs" on renewables technology such as wind would avoid high price spikes for equipment and services associated with demand-supply imbalances, particularly on hardware such as wind turbines. Further, current pursuit of the best renewable resources, such as sites with good wind patterns and proximity to transmission, allows PacifiCorp to take advantage of the cheapest opportunities to develop renewables for customers.

While reliance on current thermal generation and future thermal investments are highly likely scenarios, sole reliance on gas and coal exposes PacifiCorp to the risks they embody, with no other fuel option. Pursuing renewables for resource diversity assumes that, without revolutionary technology change, new hydrogeneration and nuclear generation are extremely unlikely in the near- to medium-term due to cost, including siting challenges and safeguards required by current regulations. Further, existing hydrogeneration is increasingly constrained by state and federal regulations.

A mix of renewable resources diversifies supply options in the generation portfolio. Geothermal is a baseload resource that complements existing thermal baseload. Solar offers a resource whose availability coincides with periods of high demand in the summer and therefore offers valuable electricity. Wind electricity is intermittent but its technological maturity provides high energy value with modularity benefits as discussed below.

Portfolio diversity benefits are further enhanced by renewables' fuel-free qualities. The value is related to natural gas prices. As gas price volatility persists, renewables look more attractive as a risk mitigation tool.

Treatment in the IRP Model

- The IRP initially included the federal renewable portfolio standard (RPS) in all modeling runs. Accordingly, 10% of system retail load (adjusted as per detailed discussion from Appendix C, Table C.17) is met by renewable electricity resources by 2020.
- The RPS was initially modeled as a flat contract with delivery to load, system integration, and shaping costs included in the $/MWh rate.
- Subsequent portfolio iterations, with the exception of Renewable, converted the flat, fixed price RPS contract with one referred to as profiled wind. The profiled wind contract is a resource modeled with a production shape reasonably representative of the resource's expected physical output, e.g. without any associated firming or shaping provided by a third party.

Multi-State Process (MSP)

In April 2002, PacifiCorp and interested parties from across PacifiCorp's service area initiated the MSP to design a mutually acceptable solution or solutions to the states' and the company's problems arising from the current approach to operating PacifiCorp as a multi-state utility. The parties entered into an MSP to develop and review possible solutions to those challenges. The MSP builds on feedback PacifiCorp received on a Structural Realignment Proposal it filed with state regulatory commissions in December 2000.

PacifiCorp's Approach to MSP

PacifiCorp is committed to designing a solution that will be mutually acceptable, durable and feasible in a multi-state environment. Through the MSP, the participants are working on a number of issues, including providing states the ability to independently implement their own energy policy objectives, establishing entitlement to the benefits of PacifiCorp's existing assets and related costs, and determining a durable allocation method for future resources. As part of the process, parties submitted potential solutions and those solutions, along with modeling that supports them, are being carefully reviewed for their ability to:

- Preserve system reliability, efficiency and safety
- Balance risks and rewards among customers and shareholders
- Be able to respond to emerging issues

Discussions are scheduled through December 2002. Once parties arrive at a solution, PacifiCorp will seek regulatory approval from each state.

Treatment In The IRP Model

Clearly, changes resulting from MSP fall into the paradigm category of risks. The risks of the MSP are among the most difficult to quantify. While a recognizable risk, MSP represents distinct and separate process. The IRP process seeks to develop a least cost plan for serving PacifiCorp's customers. MSP moves beyond the context of IRP by addressing the allocation of costs among the states. Accordingly, no model adjustments or scenarios include assumptions specifically related to MSP.

Oregon Electricity Restructuring (SB1149)

During 1999, the Oregon legislature enacted electric industry restruring, including a competition requirement for industrial and large commercial customers of both PacifiCorp and Portland General Electric Company. Under the legislation, referred to as SB1149, PacifiCorp is also required to unbundle rates for generation, transmission, distribution and other retail services, and to offer residential customers a cost-of-service rate option and a portfolio of rate options that include new renewable energy resources and market-based generation. Finally, SB1149 authorizes the OPUC to make decisions on certain matters, in particular the method for valuation of stranded costs/benefits if customers elect market access.

Implementation of SB 1149 began March 1, 2002, when PacifiCorp provided all customers with a cost-of-service rate option for an indefinite period and allowed industrial and large commercial customers a choice of energy provider. As a result of adopting SB 1149, 16 customers elected an alternate choice to cost-based standard offer tariffs. Only one large PacifiCorp customer elected market access in the choice window that closed in December of 2002.

PacifiCorp's Approach to SB 1149

Implementation of SB 1149 affects both the MSP and IRP processes. PacifiCorp continues to participate in the on-going PUC proceedings to establish the rules and procedures related to SB 1149. SB 1149 requires that

"Electric companies must include new generating resources in revenue requirement at market prices, and not at cost, and such new generating resources will not be added to an electric company's rate base even if owned by the electric company;"

Suggested revisions and interpretations of this rule generated much discussion and little agreement between parties in the recent OPUC rulemaking such that the Commission determined that further review of the issues surrounding the rule should occur in an investigation docket. PacifiCorp's current multi-jurisdictional regulatory rules do not allow the Company to make state specific resource decisions. This issue is being addressed in the MSP. As such, it is not clear at this time how the SB1149 rules can be met without either a change to the multi-state regulatory processes or a change in the SB1149 rules themselves.

In addition when parties opt out from service by PacifiCorp they must pay a stranded cost/benefit charge. One proposal discussed in the recent rulemaking was that customers should have a one-time chance to opt out with no stranded cost/benefit charge. Discussions with parties on this proposal are continuing. A durable solution coming from the MSP regarding rights and responsibilities for the Company's supply resources, which are currently shared across states, will be necessary to address the prospect of freed-up resources associated with SB1149 implementation.

Treatment In The IRP Model

A stress case was developed to determine the possible impact to the system if several industrial and large commercial customers chose another energy provider under SB1149. The major assumption for this stress was that 400 MW of flat load would leave our service territory in Oregon in July 2003. Study details and the associated findings are available in the Stress Testing section of Chapter 7.

RISK ASSESSMENT

Because of the fundamental differences between the risk categories, results of the risk analysis can not be combined into a single number. Instead, PacifiCorp has chosen a hybrid approach, which begins with Stochastic and Scenario risks being evaluated and reported as separate metrics. Therefore, several risk measures characterize each portfolio. It is likely that no single portfolio will rank highest in all risk categories. As a consequence, the methodology will not necessarily result in identifying a single optimal portfolio. However, the methodology does result in weeding out obviously bad portfolios and motivates a more focused discussion over competing portfolios that have different risk merits. The risk metrics are part of a mosaic approach used to ultimately choose the portfolio characteristics to be pursued by the IRP.

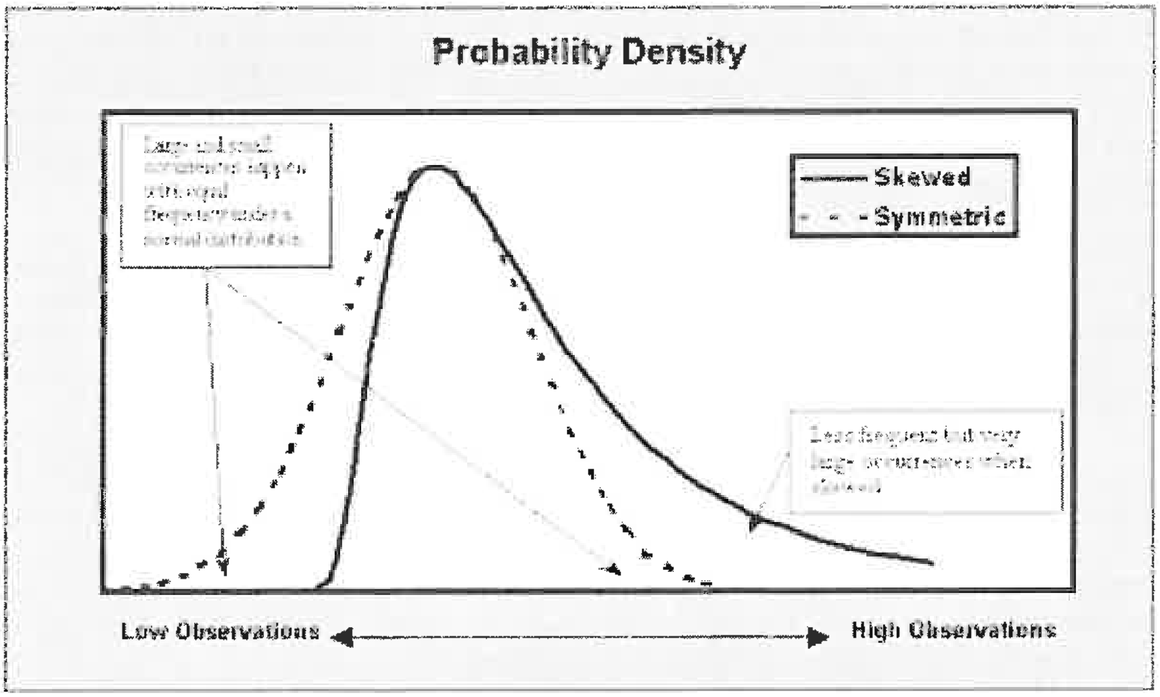
RELATIVE IMPORTANCE OF RISK CATEGORIES

Prudence requires developing a framework that will embrace all flavors of risk. However, the merit of each risk category changes as time goes by. In the past, risk associated with the electric utility business was dominated by quantifiable but difficult to probabilistically represent Scenario risks. During the periods of transition such as the one the industry is going through today, the most serious of concerns often fall in the domain of Paradigm risks. When electricity markets reach maturity, the Stochastic risks will likely prevail.

The significance of Stochastic risks should not be underestimated. It may seem that deviations of random (stochastic) variables, added on top of each other, 'wash-out'. However, statistics tells us that this is only the case when such variables are perfectly, negatively correlated. Because of this, the "jaws of uncertainty" in PVRR broaden with time. Alternatively stated, outcomes become increasingly uncertain as time progresses.

This effect is exacerbated by the non-linear dependence of PVRR on risk factors. The dependence causes the distribution of possible outcomes to be skewed. Understanding the nature of this skew is important. On a year-to-year basis, skewed distributions imply the occurrence of many, slightly smaller than expected PVRRs. More importantly, they also imply that less frequent, dramatically high PVRRs can be expected. The graph in Figure 3.3 illustrates the impact of a skewed distribution vs. a symmetrical distribution.

Figure 3.3 Probability Density



The results of the risk analysis presented in Appendix I show only seemingly moderate differences among the portfolios. In fact, the differences are hundreds of millions of dollars in size, but seem moderate since the resource additions considered by any of the portfolios are moderate compared to the size of the existing PacifiCorp system. Therefore, the differences between the portfolio risk profiles are camouflaged by the size inertia of the system. This, however, will not always be the case as electricity demand grows and the old electricity plants get decommissioned.

CUSTOMER AND SHAREHOLDER RISKS

Assessing and categorizing risk is important component of the IRP analysis. Such assessments attain greater meaning when the holders of the risk are identified. Identification is valuable analytically. It is also an important element of the IRP standards and guidelines. For example, the Utah IRP standards and guidelines include the following requirement:

> *Identify which risks will be borne by ratepayers and which will borne by shareholders.*

Based upon recent discussion with Utah commission staff, the first question stems from two issues.

1. Is PacifiCorp's participation in the market or in resource development for the benefit of customers only, or also for the potential 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 (such as risks associated with normalized costs), are costs borne by ratepayers to reduce shareholder risk?

Customers vs. Shareholder Risks

Under the regulatory compact, PacifiCorp provides cost-based electric service to retail customers. The IRP addresses the resource actions required to meet this obligation. The IRP exclusively focuses on resource actions required to meet PacifiCorp's obligation to serve retail customers. The IRP does not contemplate resource additions or market activities directly benefiting shareholders or parties other than retail customers in existing jurisdictions served by PacifiCorp.

To the extent PacifiCorp shareholders implement the IRP by prudently investing capital to provide low-cost, reliable service, shareholders have the opportunity to earn a fair, regulated rate of return, subject to ratemaking in the regulatory process. Thus, the sole shareholder benefit opportunity from the IRP is the opportunity to earn the allowed rate of return on any investments resulting from the plan. Consequently, risks borne by shareholders associated with implementing the IRP can be categorized as regulatory risks, as discussed below.

Shareholder Risks

Under perfect regulation, if PacifiCorp makes prudent investments, the investments as well as associated and reasonable expenses would be allowed fully into rates on the plant in-service date, without any lags or adjustments. However, the system is not perfect in this sense and regulatory risks are borne by shareholders. These risks include:

- Lag - delayed recovery of the investment measured relative to incidence of investment
- Allocation Gap - overlapping regulatory authorities or conflicting regulatory rules that do not allow all prudently incurred investments into rates.
- Normalization - certain costs which are normalized in ratemaking are actually incurred at higher than expected levels, during a period in which rates are not adjusted
- Disallowances - investment costs and associated expenses are disallowed because they are deemed to have not been prudently incurred at reasonable levels.

Two of the above regulatory risks borne by shareholders are examined in the IRP: (1) the Allocation Gap risk and (2) normalization risk for certain costs for a period of at least some duration in ratemaking.

Allocation Gap risk is a Paradigm Risk. It is faced by both PacifiCorp's shareholders and customers. This risk is being addressed through the MSP process and a solution is critical for resource plan implementation.

Normalization is used in ratemaking. Certain costs are normalized over the period in which rates are set. Such costs include, but may not be limited to:

- Forecast power prices,
- Fuel costs,
- Forecast load,
- Hydroelectric availability and

- Thermal outage rates,

If abnormal (and potentially non-recurring) events occur in a cost that is normalized, the risk (potentially a cost or benefit) is borne by shareholders. Extraordinary events in these areas may or may not be expected to continue to be borne by shareholders. However, changes in the trend of expectations may over time be shifted to customers by adjusting the normalized value in the succeeding rounds of ratemaking proceedings.[9]

The Stochastic Risks quantified in the IRP translate into normalization risks in ratemaking. Consequently, over time, the risk is shared between shareholders and customers. This sharing can be understood in terms of two time frames. Over a multi-year time frame, the ratemaking process will respond to the volatility of portfolio operating costs by either increasing rates if operating costs rise or decreasing rates when operating costs decline. In this time frame, these risks are borne by customers. In a shorter, between-rate-cases time frame, normalized rates do not respond to operating cost variations and such risk is borne by shareholders.

Minimization of Stochastic Risk was not a key driver in the IRP portfolio approach. Among the best performing portfolios, the exposure to Stochastic Risks, described in Chapter 7, is indeed very similar. The Paradigm Risks and the CO_2 Scenario Risks received particular consideration in the risk evaluation and contributed more to the conclusion to pursue a diversified portfolio approach.

Customer Risks

Customers face all of the risks evaluated in the IRP, including the Stochastic, Scenario and Paradigm Risks. As noted above, shareholders share some of the risks, notably normalization of Stochastic Risks and certain Paradigm Risks, including MSP. Customer risk associated with failure to solve MSP problems takes the form of inability of PacifiCorp to deliver the optimal portfolio option due to cost recovery problems or to be able to do so only at a higher cost (either capital expenditures, fuel costs or other variable costs). The customer perspective on these risks should be the driving criteria in determining the best resource strategy to pursue on behalf of these customers. PacifiCorp believes the IRP Action Plan, detailed in Chapter 9, strikes the best, prudent balance between cost and risk on behalf of its customers.

Customer Risk Tradeoff

A fundamental risk tradeoff borne by customers is the tradeoff between serving resource needs through generating assets versus serving the needs through market purchases. Resourcing through generating assets assumes assets are owned by PacifiCorp. Resourcing through market purchases assumes resources are secured through long-term firm or unit-contingent power purchase agreements (PPAs) with the purchase costs determined by cost formula.

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[9] There may also be an asymmetry to normalization risks borne by shareholders because, under regulatory treatment, the magnitude of net power cost upward excursions are virtually unlimited while the magnitude of downward excursions is limited by the high probability that low prices will remain positive.

For the purpose of highlighting this trade-off, consider this comparison of two strategies for resource planning: a Short Assets (relying on market purchases to meet load obligations) and a Long Assets (Building Assets or the above described firm or unit contingent PPAs tied to specific assets).

The risks and benefits of these two strategies can be summarized in the following categories: Electric Prices, Loads and Fuels

Electric Price Risk
The Short Assets strategy includes volatility around market price as a risk. Lower power prices would be a benefit to customers, while higher power prices would be a disadvantage to customers. Such a strategy brings greater rate fluctuation. Normalized prices used in rate cases would fluctuate annually with higher than normal or lower than normal prices. Another risk to customers is supplier risk, including both credit risk and performance risk.

A benefit of a Long Assets strategy is the price stability associated with non-reliance on market purchases. It is a form of insurance against price volatility, but as with most insurance, it comes with the cost, or premium, which is the embedded cost of the assets. There is also a risk to the Long Assets strategy if the normalized market price falls below the embedded cost of the new resource. Here the customer pays more than what market could provide under a Short Assets strategy. Another risk to customers is operations risk.

Load Risk
The Short Assets strategy is beneficial when loads unexpectedly decline or when expected load growth fails to materialize. In such instances the cost of embedded resources do not need to be spread across a smaller number of customers. Conversely, if load increases more than anticipated, PacifiCorp would be even shorter. PacifiCorp would have to rely more heavily on market purchases, which may result in higher net power costs. Higher net power costs translate to higher rates through electric price risk discussed above. However, surplus energy may have to be sold (which could be good if prices are high or bad if prices are low). No Ceiling to risk

One of the benefits of a Long Assets strategy is that if load increases, there are more assets to cover load growth and less reliance on the market. The risk, however, is that with lower-than-expected load, there is less need for already-newly-built assets, and the embedded cost of the new resources will have to be redistributed across a smaller number of customers thus resulting in higher prices. Of course planned, but unbuilt resource acquisitions can be cancelled if load is lost. Ceiling to Risk

Fuel Risk
As was discussed above, fuel risks are normalized in ratemaking. Therefore, customers and shareholders share this risk. The element of fuel risk borne by customers varies with resource strategy, as follows:

Short Assets – To the extent reliance is on Short Assets, there is not a direct Fuel price risk. However the risk is present. It resides in the market prices paid for power. Customer performance risk still exists (as a fuel risk dependency) since the customer bears the fuel risk.

Long Assets – The type of new asset would have an impact on the fuel price volatility, which impacts customer rates.

- Wind – no fuel and, thus, no market price volatility. Therefore, customers face no variable fuel price risk. . However, availability of wind could be a variable affecting rates.
- Coal – relatively stable fuel prices. Therefore customer rates would marginally be affected by changes in fuel price.
- Natural gas – inherent price volatility. Portfolios heavy in gas carry greater fuel price risk, which could either benefit or disadvantage customer rates.

Plan Cost Effectiveness

The Utah IRP standards and guidelines also call for an evaluation of cost-effective resource options from the perspective of both PacifiCorp and the different reatepayer classes. Understanding risk apportionment is one important element in the evaluation. Another is assessing the relative cost-effectiveness of the resource plan from the perspective of the utility and the different customer classes.

All customer classes share the same fundamental interest in electric service, i.e., it needs to be low cost and reliable. In general, customers face the same risks associated with selecting a resource plan strategy. It is equally presumed that the relative cost-effectiveness of the resource options is the same across customer classes. This presumption deserves one important caveat. Some customers (e.g., large industrial customers) may tolerate a lower reliability and favor a lower cost (or riskier) approach to power supply. This issue is addressed in ratemaking and with interruptible tariffs, and is not addressed as a resource planning issue. The IRP is based upon providing system-wide firm service with a reliable, low-cost system.

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 as discussed above, PacifiCorp's shareholders are neutral to the IRP decisions. The choice of resource strategy should be driven by customer interests and should seek the best available balance between cost and risk in meeting power supply needs. Lower risk options tend to impose higher fixed cost "insurance premiums" while higher risk options tend to impose lower "insurance premiums". The IRP risk analysis is primarily focused on striking the right balance to service this customer interest

CONCLUSION

PacifiCorp faces a wide variety of risks. These risks are inherently linked to the development of the Integrated Resource Plan. Given their distinct nature, different categories of risk receive different treatment within the plan.

Stochastic Risks, with an expected distribution of random outcomes are addressed directly by an analytical approach employing a Monte Carlo simulation. Scenario Risks do not have a predictable behavior but can still be reasonably represented by parameters in an analytical model. Paradigm Risks do not naturally fit a mathematically driven model and are treated separately. Planning requires thoroughly understanding the Paradigm risks, cogently monitoring their development and structuring the plan to maintain the flexibility necessary to respond to them.

Risk modeling efforts capture and emulate Stochastic risks while representing and testing reasonable ranges for Scenario risks. The results are then interpreted in light of relevant Paradigm risks. By addressing each of these categories of risk, the IRP modeling efforts provide the framework for sound decision making. The next chapter describes this modeling framework.

4. ANALYTICAL APPROACH USED IN IRP

OVERVIEW

The main analytical objective in IRP is to compare the cost (measured as PVRR) and performance (risk or variability of PVRR) of various resource plans. This Chapter highlights the analytical framework used for the IRP. It also describes the methodology for finding the portfolio(s) performing best under a range of possible futures. The information drawn from this analysis, summarized in Chapter 7, will help identify near term actions consistent with the best-performing portfolios.

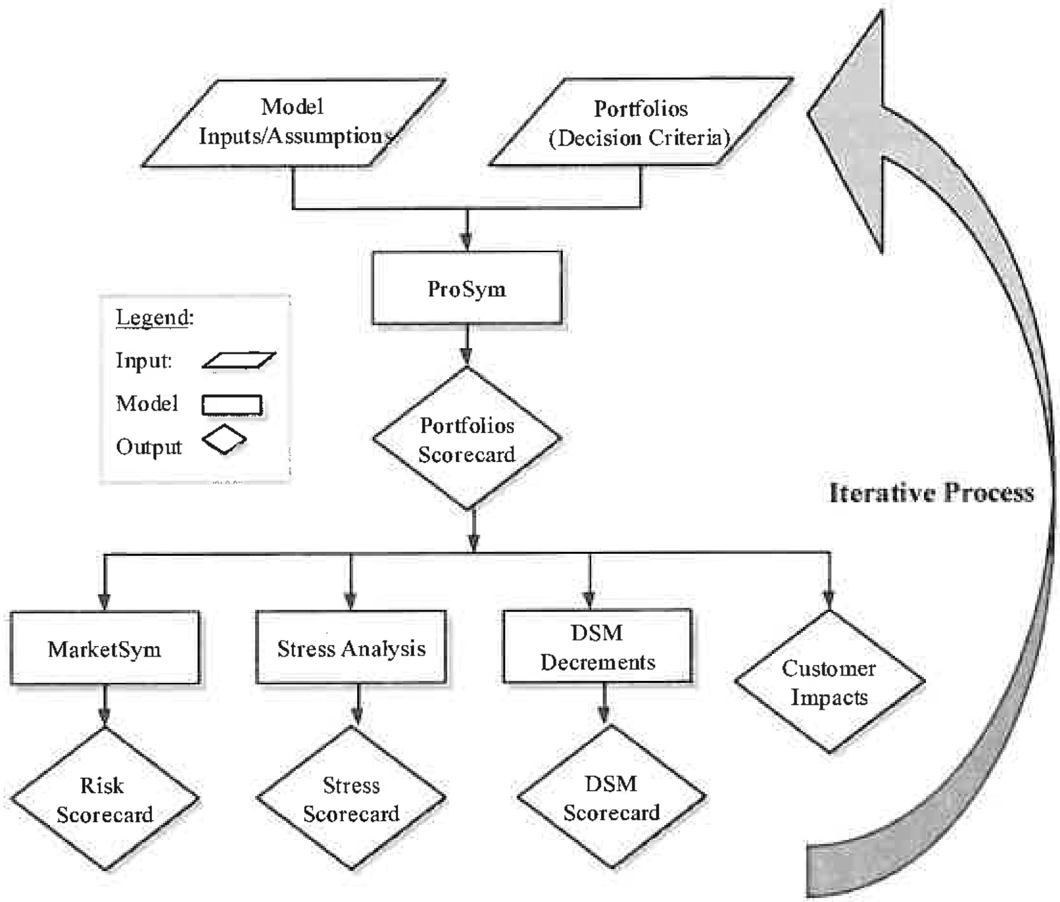
STEPS IN ANALYSIS

The analysis involves a number of distinct steps.

- **Portfolio Development:** The first step is the formulation of resource portfolios and the selection of modeling assumptions. Formulating the portfolios requires specifying the types and timing of resource additions such that anticipated loads are reliably served. Portfolios were chosen to span a complete range of likely resource strategies. Detailed assumptions are listed in Appendix C.
- **Operational Simulation:** Next, the operation of each portfolio is simulated. The simulation develops a base or reference view of the future. In so doing, this step requires calculating the operating costs of the integrated system (both the portfolio additions and the existing resource system) and other performance characteristics under a representative set of assumptions about the future.
- **Cost Analysis:** Each portfolio's system operating costs are then combined with the corresponding capital costs, yielding the PVRR, the main cost metric.
- **Screening:** The PVRR and other measures of a portfolio's performance allow a screening or winnowing of portfolios, while highlighting those with the most promising performance (lower costs). Focusing only on portfolios that survive this winnowing allows risk analysis to be performed on the most promising portfolios.
- **Risk Analysis & Stress Testing:** 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 (see Chapter 3).

The following sections provide a brief summary of each of these analytical steps. More details on the models and methods used in this analysis are provided in Appendix J. Figure 4.1 provides a high level diagrammatic representation of the IRP development process.

Figure 4.1 Analysis Process



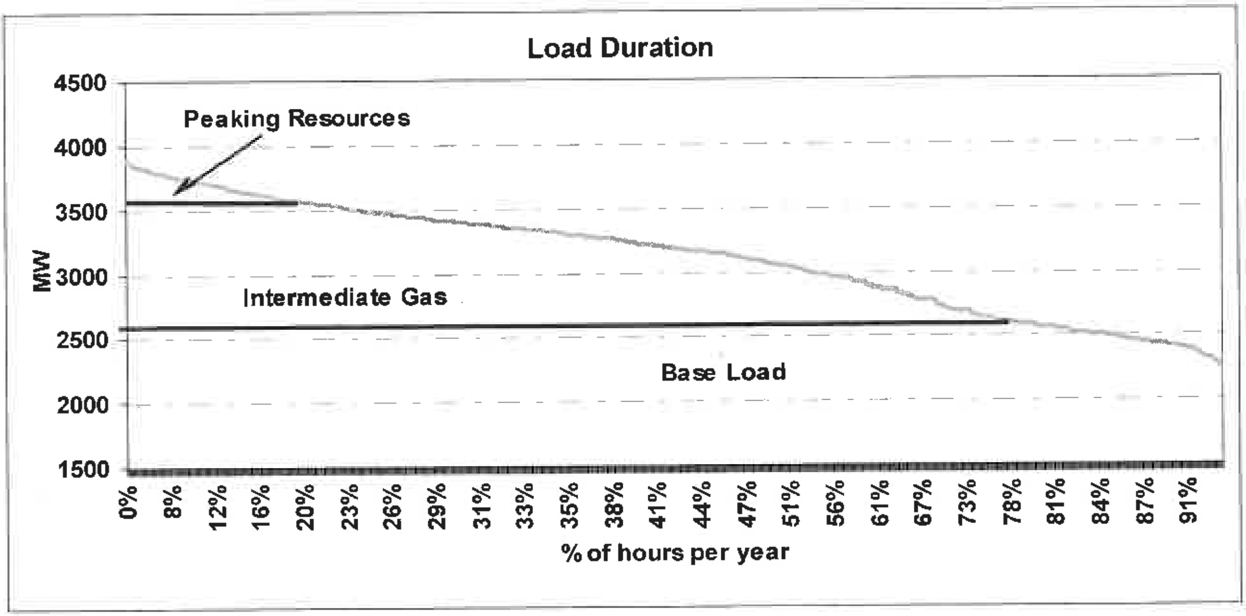
Portfolio Development

Constructing portfolios was a process of assembling system and market assumptions, estimating PacifiCorp's short position and choosing which portfolio resources are added each year to serve it. The first two boxes illustrated in Figure 4.1 represent this step.

Determining the short position began with the base demand growth forecast and the profile of energy needs. The profile combined with existing resources illustrated PacifiCorp's expected short position.

The resources described in Chapter 5 served as the set of building blocks from which each portfolio was constructed. The expected costs of each base-load, intermediate and peaking resource were used to create screening curves, guiding the selection of each building block. Helping fit the most economical resource to the shape and duration of the existing short position, the screening curve served as a simple but highly effective tool to minimize portfolio costs.

Figure 4.2 Sample Resource Deployment Curve



As illustrated in the figure above, the selection of building blocks depended upon the size and duration of the short position. Large, long duration short positions were filled with base load resources (coal and/or CCCT gas), since resource screening curves show these are the lowest cost resources when required to operate at high capacity factors. Smaller short positions were filled with intermediate gas resources. Finally, the remaining short position was filled with peakers. This process was repeated every year until the portfolio was completed.

Building a portfolio was not merely a process of randomly adding resources. Guidelines were established to bound portfolio development. For example, resources were added to limit expected spot purchases to 5% or less of each year's hours. Furthermore, a required planning reserve margin was used to determine any additional capacity resource requirements. A 15% planning reserve margin was used as primary criterion. An alternative of 10% was also tested. Appendix J summarizes the decision process leading to the 5% and 15% limitations.

During the public process surrounding the development of this IRP, significant discussion around "automatic resource addition logic" occurred. PacifiCorp recognizes the potential merit of automatic resource addition logic. The lessons learned from this portfolio building exercise may allow PacifiCorp to include such logic in the next iteration of this IRP. Clearly such logic is complex and for it to be a value adding exercise, much more than construction of a resource addition stack dependent on dispatch cost is required. PacifiCorp is committed to exploring the addition of this logic in the next IRP.

As a result of the resource addition guidelines, each portfolio of new contracts and generation covered much of the anticipated short position. Market purchases satisfy any remaining short position. These guidelines served to constrain PacifiCorp's exposure to volatile wholesale electricity markets.

341, 500 MW limit

While each portfolio differed, groups of portfolios tended to share common characteristics. The following categories evolved:

- PacifiCorp Build
- Transmission
- Diversified Generation
- Renewable
- All-Gas

Details regarding the portfolios and categories are available in Chapter 6. A detailed, step-by-step description of the portfolio development process can be found in Appendix K.

Operational Simulation

With candidate portfolios assembled, PacifiCorp simulated the combined hourly operation of its system and the additions. For this purpose, PacifiCorp employed PROSYM, a detailed hourly operations simulation model. PROSYM provides a very precise analysis of resource interactions and the resulting operating costs. Accordingly, the PROSYM box in Figure 4.1 represents this step. Details regarding the PROSYM model can be found in Appendix I.

Before providing output, the model first consumes enormous amounts of data. This kind of resource modeling requires very detailed information including:

- Transmission constraints
- Market price forecasts
- Market price variability
- Resource operating characteristics, and
- The hourly shape of demand

Assumptions for these inputs are important. Changes in each can make a large difference. Market price forecasts begin with PIRA Energy's long range forecast of natural gas prices. PacifiCorp's fundamental WECC market model, MIDAS, uses the gas forecast to generate forward electricity prices. Details of the MIDAS model assumptions and methods are described in Appendix I. Assumptions regarding transmission as well as existing and proposed resources are listed in Appendix C and Chapter 5, respectively.

The above inputs are processed and the resulting operating costs are determined. PROSYM also provides a rich array of other details. These include:

- Unit capacity factors
- Transmission loading
- Planning margin
- Market purchases / sales
- Emissions

Combined with operating costs, these factors provide valuable information as to how successfully a portfolio meets its intended purposes. Scorecards, detailed in Appendix E, consolidate and summarize the cost output of PROSYM.

Cost Analysis

Operating costs represent only part of a portfolio's cost profile. An accounting for capital costs must also be made. Capital costs are a function of the kinds of resources in each portfolio and the timing of their addition.

A simple discounted cash flow model combines the capital and operating costs and calculates the PVRR of each portfolio. Real levelized capital was used in the revenue requirement calculation to allow reasonable life cycle cost comparison. (See Appendix K for more details on levelized vs. nominal capital costs.)

Screening

With the completion of the previous steps, we obtain a detailed representation of each portfolio. A series of summaries, called scorecards, are assembled for comparative purposes. The scorecards provide comparisons of each portfolio's

- PVRR,
- Capital Costs,
- Emissions,
- Market Purchases
- Market Sales
- Unit Capacity Factors, and
- Transfers

Using the portfolio scorecards, PacifiCorp narrowed the list of candidate portfolios for stress testing, risk performance measurement and other general analysis. Selected portfolios had superior PVRRs and preferred operating characteristics. Portfolios meeting the 15% and the 10% reserve margin standard were selected, so as to analyze the effect of this significant planning choice.

Risk Analysis and Stress Testing

The narrowed list of portfolios was analyzed to assess their risk characteristics. Many of the characteristics necessary to simulate operations and calculate net electricity cost are uncertain. PacifiCorp analyzed the effect of varying these Stochastic Risks using the MarketSym model.

MarketSym develops a large number of scenarios using a statistically valid sampling of the risk parameters. Parameters are randomly varied based on our understanding of the correlation among them as well as their expected values and variability through time. 100 such scenarios were used to test the performance of the portfolios and provide a detailed picture of portfolio performance over a wide range of environments.

Like PROSYM, MarketSym used a detailed hourly dispatch simulation. Unlike PROSYM, the model varied the input risk parameters. Also, to obtain required computational speed, the model employed a simplified transmission representation.

In addition to modeling stochastic risks to observe portfolio performance, several Scenario Risk parameters were modified for the purpose of stress testing the portfolios. Such testing provided performance information over a range of assumed circumstances and allowed the modeling of the impact of parameters without inherently definable, randomly moving characteristics.

A detailed description of each of the risks and the manner it was addressed is available in Chapter 3.

OPTIMIZATION

The IRP's analytical process was, in part, an exercise in portfolio least cost optimization. The convergence of different portfolio PVRRs and rapidly decreasing cost improvements associated with recent modifications, presented later in Chapter 7, are clear signs that portfolios are approaching, if they haven't already attained, optimality. While the *results* of the optimization process are apparent, the presence of the optimization *process* may not be obvious. The information below summarizes some of the procedures, rules and heuristics employed in this process.

Portfolio Screening Curve

Discussed earlier in this chapter, portfolios were constructed to fit PacifiCorp's short position. Individual resources were selected according to a screening curve such that segments of the short position were matched with the most cost effective resources to serve them. Figure 4.2 illustrates the approach.

The screening curve was a powerful first step in the optimization process. The curve served to remove obviously impractical resource solutions from consideration and dramatically reduced the number of model runs needed for the analysis.

Theories and Themes

Pursuant to the screening curve, various resource theories and themes were tested. Chapter 6 summarizes the major areas of research which include:

- The effect of altering the order of gas and coal plant installation
- The impact of using coal vs. gas for base load resources
- The value of replacing base load gas resources with multiple, highly flexible peakers
- The effect of altering the timing of base load installation
- The value derived from purchasing contracts vs. resource development.
- The benefit of adding and removing renewable resources.
- The value of greatly expanding East-West transmission links

Portfolios within these themes were modified and improved through an iterative process, serving to identify and eliminate less desirable characteristics. Accordingly, numerous portfolios were generated and tested. For the sake of time and space Chapter 7 and Appendix E list and describe 22 of the major portfolios tested. Detailed discussions are limited to the top four Diversified as well as the Renewable portfolios.

Operational Signals

The model simulated portfolio operations and summarized the results. The operating results provided insight into each portfolio's dispatch profile. They also signaled the presence of inefficient operation. In light of such signals, portfolios were iteratively modified and re-run to produce lower cost configurations.

The following items provide examples of some signals:

- Low capacity utilization factors signaled surplus capacity and suggested the elimination or postponement of resource additions.
- High market purchases signaled a potential under-build of resources.
- High emissions costs signaled sensitivity to Scenario Risks like CO2 taxes and suggested modifications and stress tests.

Cost and Risk Analysis

Successful portfolios presented superior cost and risk results. As different portfolio configurations were exhausted, themes with consistently inferior results were eliminated from further consideration. For example the Peakers portfolios (replacing gas base-load with peaking units) as well as the Transmission portfolio strategies consistently diverged from the PVRRs of the top portfolios.

Industry Expertise

Perhaps the most important element of the optimization process is the industry and operating experience employed in the development and testing of the portfolios. The modeling process drew upon the experience of individuals inside PacifiCorp. It also drew upon a wealth of intellectual capital outside PacifiCorp through consultants and the public process. Such experience helped identify and overcome operating constraints and capture system benefits in the simulations. It also helped identify portfolio flaws as well as intuit promising areas of research.

Convergence

The clearest sign of the success of an optimization process is convergence. Convergence within the IRP is revealed into two ways.

1. Recent, successive iterations provide decreasing, if any, additional cost benefits. Such a progression would be expected as portfolio configurations approach or achieve optimality.

2. The cost and risk differences between top portfolios collapses. As representatives of different, surviving portfolio categories individually approach an optimum, it is expected that the cost and risk differences between the different portfolios collapse.

CONCLUSION

PacifiCorp performed a thoughtful and comprehensive analysis. The analysis began by constructing various portfolios of new resources and then simulating their performance within a model of PacifiCorp's system and operating environment. From this analysis, PacifiCorp obtained detailed information regarding each portfolio's costs, performance and risk characteristics. The output was used by PacifiCorp to draw conclusions about strategies with the best cost and risk profiles and naturally leads to the development of a plan of action.

basis. This type of DSM could negatively affect business economic output. Load reduction endures only for the duration, in hours, of the incentive offering. Permanent facility and equipment changes or improvements are not made. There is no persistence in the load reductions.

Examples include the Energy Exchange program, curtailable tariffs, or real-time pricing

Class 4

Non-dispatchable, conservation education: Energy and capacity reductions achieved through behavioral changes. Specific program results cannot be relied upon for planning purposes. Long-term, persistent changes will be seen in historical load growth pattern changes over time.

Examples include Power Forward, 20/20 Customer Challenge, public education and awareness programs that promote energy-reducing methods such as conservative thermostat settings, turning off appliances when not in use, and inverted block and time-of-use pricing structures.

Future Programs

In addition to existing DSM programs listed in Chapter 2 that will be considered for expansion, new programs under consideration include:

Residential

Class 1

- Central electric air conditioner load control (residential and small commercial)
- Irrigation load control

Class 2

- Comprehensive residential cooling efficiency. Promote use of fans, evaporative cooling, and high-efficiency air conditioning above federal standards.
- Appliance recycling - Early replacement of old refrigerators and elimination of second refrigerators.
- Energy Star appliance promotion - promote Energy Star appliances which includes incentives for efficient clothes washers that save energy and water.
- "Best practice" AC servicing program to provide targeted tune-up of cooling systems.

Nonresidential

Class 1

- Central electric air conditioner load control
- Irrigation load control

Class 2

- Retrofit Building Commissioning - a process for "tuning up" systems in buildings and getting them to work properly, thereby improving the energy performance and comfort in existing buildings.
- Expansion of Energy FinAnswer program.

Class 3

- New commercial and industrial interruptible, curtailable tariffs and real-time pricing.

In addition to these specific potential programs, we are modeling further decrements to the load forecast in the IRP model to determine the value of additional load reductions at various load factors. Further program designs will be considered and the model re-run with these actual program load decrements. Further description of this decrement approach is contained in Appendix G.

SUPPLY SIDE RESOURCES

For the purpose of modeling portfolios, PacifiCorp has identified a list of prospective resources for balancing resource supply with electricity demand based on options uniquely available to PacifiCorp. Table C.18 in Appendix C lists these resources and their specific operating characteristics.

Candidate Supply Side Resources Used in the IRP Analysis

Utah Coal Options

The addition of a fourth unit (Hunter 4) at the existing Hunter Plant in central Utah was selected to represent a state of the art pulverized-coal plant option for the IRP. Hunter 4 would use the latest available emission control technology for SO_2, NOx, and particulate. This unit would remove more than 97% of the SO_2 produced and would incorporate Selective Catalytic Reduction (SCR) to control NOx emissions to less than 0.08 lb. NOx/mmBtu. The Hunter site is presently viewed as an excellent company owned location for an additional unit because the existing units already there would lend supporting infrastructure (substation and transmission included) and manpower to its operation. It is also close to sufficient coal resources to fuel the unit.

The Utah Greenfield PC represents a new coal plant at a completely new generation site in the Utah area. Costs for the greenfield facility are based upon a two unit plant (to achieve economies of scale) using the Hunter 4 design. These costs are higher than those of Hunter 4 simply because of the inability to use common facilities, as compared to the common facilities already existing at the Hunter Plant.

IGCC is a clean coal technology that utilizes a coal gasification process to produce clean fuel gas that can then be used to fuel a combined cycle gas turbine. This technology can achieve slightly lower pollutant emission levels and higher efficiencies than a conventional coal-fired plant. However, IGCC is only now beginning to reach full commercialization. There are a half a dozen or so commercial plants in the world to date and most of these are fueled by petroleum residuals. Capacity factors for these plants typically have been less than 80%. Nevertheless, work is being done to improve their operation on both coal and petroleum residuals and progress in this area is expected. Capital and operating costs are now higher than those of traditional coal-fired plants, but these could come down as larger economies of scale are reached. IGCC production costs in the Utah and Wyoming areas will be further disadvantaged compared to lower elevation areas because of elevation de-rating of the gas turbines. Most of the Utah and Wyoming coal sites are at relatively high elevations. PacifiCorp will continue to follow this technology for future additions as the technology becomes more established and the cost decreases.

Wyoming Coal

Because Wyoming has large quantities of low cost coal, new conventional coal plants there are a definite possibility. A fifth unit at the Jim Bridger Plant represents the first 500 MW plant shown for Wyoming. Additional units would be built near the Powder River Basin coal area. Capital costs for all of these units were derived from the design and cost for Hunter 4, a plant of similar size. However until transmission constraints in Wyoming are removed, it will be economically difficult to justify building a new coal plant there.

Combined Heat and Power (CHP or cogeneration)

Utah CHP was developed to represent a cogeneration opportunity along the Wasatch Front. The "Cogen-CT" CHP represents a combustion turbine generating steam for industrial purposes. A large CT is modeled. This option is dependent on the proper host and is considered a low probability considering the industrial base in Utah. The "Non CT" case is intended to be a boiler or waste heat application that could apply a topping steam turbine at relatively low cost. No specific candidate cogeneration sites are currently identified.

Geothermal

Renewable energy could be added to the resource portfolio with the addition of more geothermal capacity at the Blundell Plant. The 50 MW block of electricity shown represents the cost of adding bottoming cycle to the current Blundell Plant and then adding an additional flash and bottoming cycle system. This is a very realistic option currently under review by PacifiCorp. Total capacity of the Blundell Plant with the addition of the Blundell Upgrade would be about 75 MW.

Two other geothermal sites are considered for modeling purposes. These are known sites with some development work completed and known potential plant capacity evaluated. One is a 50 MW site near the current Blundell plant in Utah. The second is a 50 MW Newberry volcano site in central Oregon, near the city of Bend. Other sites will also be considered, as information becomes available.

Fuel Cells

Fuel cell technology continues to improve and become more cost effective. A fuel cell is an electricity-generating device, fueled by natural gas, that utilizes the reaction between hydrogen and oxygen with the only by product being water. Attractive fuel cell characteristics include:

- High energy conversion efficiency
- Modular design
- Very low chemical and acoustical pollution
- Fuel flexibility
- Cogeneration capability
- Rapid load response.

Disadvantages include high capital costs and technological uncertainty.

Market Purchases/Contracts

Market Representation Assumptions

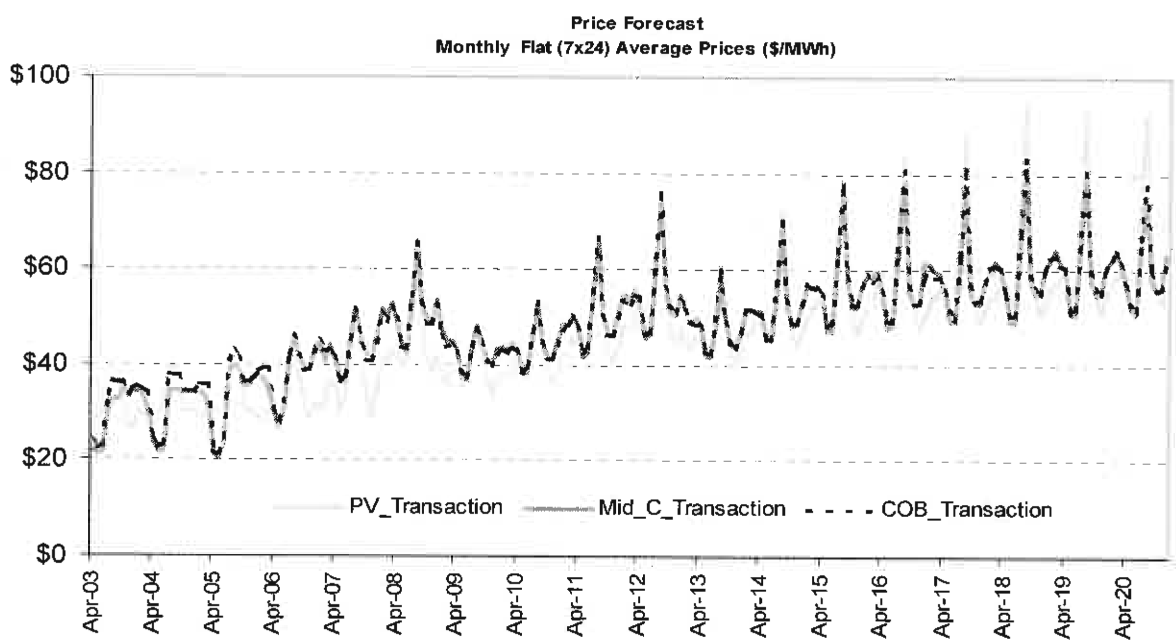
The process of developing portfolios must also contemplate supplemental access to the spot market. PacifiCorp considered several methods for representing market purchases and sales. Initial studies included few limitations on spot market transactions. This raised concerns regarding the extent to which spot markets could reasonably be depended upon to meet short duration peak deficits and to follow load during light load and shoulder hours. Exempt from such considerations, the studies tended to undervalue load-following and peaking resources.

To better represent market limitations, the availability of market purchases was constrained. The limitations are described in more detail below:

- Three markets are represented in the model (Palo Verde, Mid Columbia, and COB)
- Purchases and sales were limited at each (250 MW each at Mid Columbia and COB, and 500 MW at Palo Verde).
- Transmission congestion issues and limited firm transmission rights in the East require a transmission cost associated with reaching the Palo Verde market.
- Purchases and sales into these stations have no ramp rate, minimum up time, minimum down time, or startup cost restrictions.

The markets are meant to represent the flexibility of hourly transactions that routinely take place on the system to help balance loads and resources. Figure 5.1 provides a graphical depiction of the price forecast used in the modeling.

Figure 5.1 IRP Price Forecast – Monthly Flat , Average Prices



Asset-Based, Long Term Power Purchase Agreements (PPA's)
All market purchases used in building portfolios are modeled as PPA's that are tied to physical assets. These purchases are from energy merchants and other industrials offering surplus electricity that they have available. Contracts are modeled such as would be used in real life and are modeled to perform accordingly. Most contracts have fixed prices and are used in the heavy demand hours; the price of several contracts tie to indices and so will dispatch based on least cost as compared to their associated markets.

A review of WECC-wide load as compared to WECC-wide resources suggests there will be an over-supply of generation available in the next five years. The over supply will largely be as a result of more than 16,500 MW of new generation currently under construction (plus approximately 15,500 MW new generation between January 2000 and August 2002). However, due to transmission constraints, additional transmission capacity would have to be built to reach the load centers.

Shaped-Products
Several short term Power Purchase Agreements (PPAs) from energy merchants and others are available to PacifiCorp today and availability of these products is expected to continue in the future. While not all these shaped products are explicitly modeled in the portfolios, they will be used in the future to meet load requirements if the cost/risk balance at the time is appropriate for the customers and PacifiCorp.

The following is a list of energy or shaped-products that PacifiCorp would consider purchasing from credit-worthy market participants if they exist:

- **Call Option with fixed premium** – The option buyer has the right but not the obligation to buy energy and capacity at specific rates at a defined strike price. The buyer would exercise this right when market prices exceed the strike price. This option provides price protection from high prices.
- **Put Option with fixed premium** – The option buyer has the right but not the obligation to put, or sell, energy and capacity at specific rates at a defined strike price. The buyer exercises this right when market prices are below the strike price. This option provides price protection from low prices.
- **Swap** – A swap is an exchange of cash flows between a swap seller and the swap buyer. The swap seller owns capacity and energy at a fixed price and has exposure if market prices move lower (a coal plant for example). The swap buyer needs energy and capacity and purchases this requirement each day and has exposure if prices move higher (a marketer without generation). The swap seller hedges his position by selling a notional (financial) quantity of energy and capacity to the buyer at a fixed price. The swap allows the seller to hedge his fixed price risk and allows the buyer to hedge his index or daily price risk.
- **Tolling Option with fixed premium** - The option buyer has the right but not the obligation to call, or buy, energy and capacity at specific rates at a defined heat rate multiplied by a gas price index (energy price). The buyer would exercise this right when market price for electricity exceeds this energy price. This option provides protection from high prices and might be used instead of a call option with a fixed strike price.

- **Straight Block Purchases (e.g. 6 x 16, 7 x 24)** – Buyer has the obligation to take and pay for energy and capacity at specific rates at a fixed price. The buyer needs energy and capacity and purchases this requirement each day and has exposure if prices move. The buyer reduces his floating price exposure and receives energy and capacity at a fixed price. The seller reduces his index price exposure and sells energy and capacity at a fixed price.

Natural Gas

<u>Natural Gas East Side</u>

Several options exist in the Utah area for new natural gas-fired electricity plants all based on using gas turbines. Gas turbines in the Utah area are assumed to be located at an elevation of 4,500 feet and would experience a de-rating of 15% from ISO values due to this elevation. Additionally the ratings used are based on a 90° F summer type condition since Utah is a summer peaking application.

Simple-cycle Combustion Turbines (SCCTs) are modeled. These machines are true peakers and are represented by aero (aeroderivative) machines such as the LM6000 design from GE recently installed at West Valley and Gadsby. These machines have high efficiency and can start within 10 minutes to qualify as spinning reserves.

The Frame machine represents another type of SCCT. These heavy-duty industrial combustion turbines are generally larger, lower in first cost, less efficient, and have longer start times than the aero machines. A Siemens-Westinghouse 501D5A machine was used to represent this option. The Brownfield SCCT Frame Mona option represents this type of machine located away from the Wasatch Front to allow installation without maximum NOx control. Not installing SCR for NOx on this type of machine will save considerable capital cost but would most likely involve operating restrictions in the form of reduced allowed operating hours. Limited hours of operation may be acceptable if the machine is installed mainly for super-peak type capacity.

Combined-Cycle Combustion Turbines (CCCT) are also modeled. On the Utah side, an addition to the Gadsby Plant is shown as either a single 1x1 machine or a CCCT in a 2x1 configuration. Emission controls are assumed to be Best Available Control Technology (BACT). A 2x1 configuration (two gas turbines and one steam turbine) is the best representation for a base-loaded CCCT with a capacity factor greater than 70%. For more intermediate duty (capacity factors between 30% and 70%) the 1x1 configuration will be a better application. The 1x1 design will be easier to start and stop on a frequent basis and will have a quicker starting time profile. The O&M costs for the 1x1 options reflect the additional starts associated with intermediate operation.

Combined cycle equipment is also modeled with the option of adding duct firing for additional peak capacity. This option may or may not be available with all CCCT suppliers but has been included to reflect the capability of the GE machines used. Duct firing will require additional investment in gas burners and the steam turbine system. It is expected that environmental constraints may limit the capacity factor of installed duct firing to an equivalent of 15% capacity factor.

Natural Gas West Side

Similar natural gas options are available on the West Side as were identified on the East Side of the PacifiCorp system. Simple cycle and combined cycle gas turbine representative installations on the West Side of the system have been adjusted for an elevation near the Hermiston Plant. The equipment ratings are based on an elevation of 1500 feet, which results in a 5% derating from ISO conditions. The 90-degree Fahrenheit rating has been maintained.

Wind

Wind generation has been represented in the IRP model for east and west control areas in two ways. Initially, wind resources were modeled at the proposed Federal RPS level as a flat 7x24 product purchased at $50/MWh in 2002 dollars, escalating at inflation in all the IRP Portfolios. This rate includes obtaining any tax benefits in the negotiated price from the developer as well as an assumption regarding integration costs, capital, O&M, and transmission. Estimates are included in Appendix L. Table 5.2 provides an overview of the planned build up of the RPS.

Table 5.2 The planned build up of RPS over the period 2005 to 2013

Year	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
% of Resources	1.0	1.6	2.2	2.8	3.4	4.0	4.6	5.2	5.8
Cumulative MW (Capacity)	60	186	318	414	546	687	834	981	1,146

All of the final portfolios contain wind resources that were modeled with representative wind electricity production shapes according to site location. The hourly wind sites were created on simulated historical hourly generation data from Stateline and actual historical data from Foote Creek. These two data streams were modified by lagging by one hour and moving data ahead one hour to create four new data ranges for the model. The two Stateline streams were added together and then sized to the maximum capacity of the Yakima and Bend sites in the West with a capacity factor of 32%. The two new Foote Creek sites were combined and prorated up to the maximum capacity of the Evanston and Tooele sites in the East control area with a 36% capacity factor. A single year of hourly generation was repeated over the 20-year life of the study. Further information is still required on the actual quality and location of sites.

The cost of installed wind capacity is based on the latest Northwest Power Planning Council (NWPPC) estimates of $1000/kW. Total $/MWh costs are sensitive to expected capacity factor, which are modeled as described above, and include fixed O&M, transmission, system integration costs, the production tax credit, and green tag value. Further detail on system integration and pricing can be found in Appendix L.

For modeling purposes PacifiCorp assumes it can take advantage of Federal wind energy tax credits, a wind energy production tax credit applied to energy delivered, when the company builds and owns new wind generation projects and produces electricity. Whether PacifiCorp can or cannot take full advantage of these production tax credits in any given year depends upon the company's tax situation in that year. PacifiCorp from time to time may be subject to the alternative minimum tax which would limit its ability to fully use tax credits. The wind energy tax credit can be carried forward; however, this results in less value from the tax credit because

PacifiCorp loses the time value due to the delay in cash flow from the tax credit. The economics of a wind facility is adversely impacted if the credit is not allowed in the year of production.

Supply Side Resources Not Used in the IRP Analysis

Certain resources listed in Table C.18 in Appendix C are not currently considered feasible for meeting PacifiCorp's resource needs. These include nuclear resources, tidal action resources, microturbines, and others that are either not commercially available or are clearly not cost effective based on earlier IRP analysis.

Two options that are currently not being included in IRP portfolio analysis due to cost, but are being monitored closely for future use, include pumped storage and solar.

The pumped storage option was not cost effective based on the known location. The pumped storage option represented in Table C.18 was a potential project near Las Vegas. This 400 MW project would take off-peak coal-fired generation and use the energy to pump water into a reservoir. Water from the reservoir would then be released to spin the pumps as a generator to provide peaking electricity. The 400 MW capacity could be used about four hours during a day under this operating scenario.

The solar options in Table C.18 are represented by a solar thermal plant similar to Solar II that was demonstrated in the California desert in from 1996 to 1999 with PacifiCorp's participation. Molten salt is used as a heat reservoir to get a capacity factor of better than 63% and to avoid equipment down time during cloudy days.

Photovoltaic projects are not listed due to the extreme cost of this technology for large electrical production needs.

TRANSMISSION

Several upgrades and additions to the Transmission network are necessary to further optimize the use of the network, provide greater access to market or support the addition of new assets. As mentioned in Chapter 2, the main area of congestion on the system is Utah, therefore the focus of this section will be on explaining the current situation in Utah and how the portfolios were built to relieve transmission congestion issues.

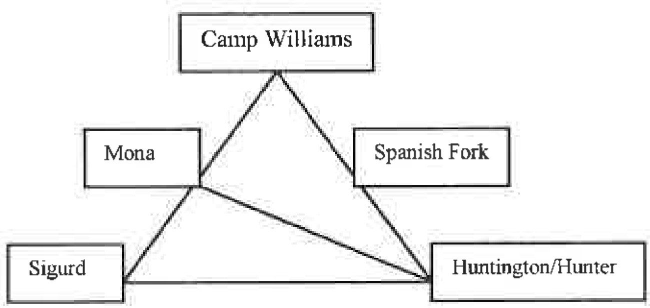
The simultaneous import capability into the Utah Bubble is significantly lower than the sum of the individual non-simultaneous path limits, as it is not possible to reach each path limit at the same time due to loop flow. In other words the one-path limit is reached while there is remaining capacity on other paths that cannot be realized. The Mona entry is excluded from the simultaneous import limit total, as it ties into the center of the Utah Bubble.

Load growth further saturates the existing transmission system. Additional transmission facilities were needed north of Mona in all portfolios to bring power into the Wasatch Front. These additions consist of a new Static Var Compensator (SVC) at the Wasatch Front load center for voltage support, and new breaker additions at Mona and Spanish Fork substations to "loop in" existing 345 kV lines for increased transfer capability from Mona to the Wasatch Front load center. These additions by Fiscal Year 2005 increase the Mona to the Wasatch Front interface capability by 500 MW increasing the available capacity north of Mona to 1,000 MW.

The southern entries into Utah consist of three lines: Four Corners to Pinto to Huntington 345 kV, Harry Allen to Red Butte to Sigurd 345 kV, and Glen Canyon to Sigurd 230 kV. These lines span southern Utah to the north, connecting to the main Utah grid at Sigurd and Hunter/Huntington. These two network nodes interconnect to the main Utah grid, forming a triangle with Camp Williams and Spanish Fork the entrance points into the Wasatch Front. The three legs of the triangle are:

1. Two 345 kV lines from Hunter/Huntington to Sigurd
2. Two 345 kV lines from Sigurd to Camp Williams and one from Huntington to Camp Williams, connecting through Mona; making Mona a natural trading hub. Two 345 kV lines from Hunter/ Huntington to Spanish Fork to Camp Williams; the triangle depictions is as shown in Figure 5.2.

Figure 5.2 Utah Main Transmission Triangle



The close proximity of Mona to the Wasatch Front makes it a practical site for building, optimizing the capital requirement for transmission integration. This is the logic for targeting Mona in the IRP for an additional 1,000 MW of resources. Hence, reinforcement to the triangle was nominated to integrate the incremental addition. The Nevada market, via Harry Allen to Red Butte is then pursued beyond the 1,000 MW capability at Mona.

Transmission facilities were also added south of Mona when additional resources were delivered from points south (i.e. Hunter, Nevada). Such resources also require additional reinforcement to the triangle when these southern resources plus Mona resources were in excess of 1,000 MW.

In addition to these upgrades and additions, transmission options were considered for opening up and building greater flexibility into the system. Two DC transmission lines of 1,000 MW and 2,000 MW DC transmission lines were considered, which would increase the bi-directional line capacity between the East and West control areas.

6. PORTFOLIOS

OVERVIEW

This describes the portfolios that were evaluated based on the methodology described in Appendix J. Each portfolio contains realistic, feasible demand side and supply side alternatives for balancing resource supply with electricity demand. Timing and size of these alternatives are compared between portfolios.

While the majority of the individual portfolios were developed based on the methodology that required a 15% planning margin, a stress case was tested on some of the portfolios using a 10% planning margin. These portfolios were developed to compare the financial, operational, risk, and customer impacts of a 10% versus a 15% planning margin. These portfolios can be identified by the '-10%' after the portfolio name. The results of this stress will be discussed in Chapter 7.

A detailed description of each portfolio is located in Appendix D. The tables in Appendix D contain portfolio names, resource types, size and timing of installation, and total megawatts installed. Transmission installations and estimated costs required for each portfolio, along with capital costs of resources are also provided. The Appendix should be consulted for details on the resource mix and addition dates for each portfolio.

The Chapter will begin by discussing some of the factors and metrics common to all the portfolios that were developed. There will then be an overview of some of the observations and conclusions that can be drawn from the portfolio development process. An overview of the first iteration of portfolios based on portfolio category will be provided, along with the benefits, issues and uncertainties associated with each portfolio category. And finally, a discussion on how the portfolios were further refined ("hybrid portfolios") by taking the best of all portfolios and combining them to achieve the least-cost solution.

COMMON FACTORS & METRICS

Several resource additions are common to all portfolios and contribute substantially to future resource requirements. All portfolios required substantial resource additions to meet base demand growth of 2.2% East and 2.0% West per year, on average, to replace resources that are lost through attrition of the existing base of resources and to cover the 15% planning margin. Total system resource additions of approximately 4,000 MW are required in the next ten years. Additions are required in both East and West control areas.

DSM

All portfolios share base DSM investments, beginning in 2004 and steadily increase their contributions to 146 MWa by 2013 of Class 2 DSM and 91 MW of Class 1 DSM. This base DSM resource is included whether the system is built to 10% or 15% reserve margin. Additional DSM resources are evaluated as stresses to the final portfolio using the decrement analysis technique which is described in Appendix G.

Wind Resource Additions

The portfolios that were developed in the beginning of the analysis contained common wind resource additions based on the levels required in the proposed Federal Renewable Portfolio Standard (RPS). The wind additions began in 2006 and grew to about 1,150 MW by 2013, and were modeled as a $50/MWh flat contract. A flat contract provides equal delivery of energy in every hour of the day.

In the final portfolios, the $50/MWh flat contract was replaced with "profiled wind", i.e. wind whose profile follows an anticipated, more realistic production shape. Under profiled wind, energy deliveries are anticipated to differ in each hour of the day. This profiled wind has been included based solely on its economic merits.

Short-Term Purchases

All portfolios require short-term purchases to meet capacity and energy needs for the 2004-2006 period. These purchases will be secured from the marketplace. Capacity purchases of 225 MW for summer super-peak hours are indicated for PacifiCorp's eastern control area. In the western control area, purchases of 500 MWa of off-peak energy are required. The timing of this need appears to coincide with a likely temporary over-supply situation in western electricity markets. These near-term purchases are required whether a 10% or 15% reserve margin is adopted.

Reserve Peakers

If a 15% reserve margin is adopted, an additional 430 MW of reserve peaking generation are required in 2006. In general, 200 MW are needed in the eastern control area and 230 MW in the western control area. By 2007-2008, additional capacity resources are needed to meet reserve capacity needs of either the 10% or 15% reserve margin requirements.

PORTFOLIO DEVELOPMENT

The portfolio development process discussed in Chapter 4 and Appendix J provided a number of useful insights. Many observations and conclusions could be drawn at the portfolio development stage of modeling. Model runs and subsequent analysis further clarified these initial observations and conclusions. They are as follows:

Base Load

The East and the West systems require additional base load resources in the future. Existing plant retirements, load growth, and long-term purchase contract expirations all contribute to this need and are common to all portfolios. The net position duration curves for the system show large gaps for greater than 60% of all hours by 2008. All portfolios fill this need for base load resources with combined cycle units and/or coal fired resources.

Peaking
Every portfolio required at least 1,000 MW of peaking resources to meet the needs of additional capacity for the planning margin. Peakers are lower cost capacity options, which provide the necessary operational flexibility to manage system reliability requirements. The gap in the West can be described as a base load profile, though the addition of peaking units provides the reserves necessary to meet the planning margin.

Shaped Products
Shaped products and electricity purchase agreements (PPAs) help resolve some of the immediate requirements for on-peak energy in the East and the off-peak gap in the West prior to actual physical assets being built. It is expected that any build option will be compared to the equivalent available shaped product or PPA at the time the decision to proceed with the build option has to be made. It is anticipated that the majority of shaped products and PPAs will be closely linked to physical assets to ensure the capacity is available. Shaped products will also be procured to hedge and reduce the risk exposure to variations in thermal, hydro and wind performance.

Transmission
Every portfolio involves some investment in transmission upgrades. Without transmission improvements, the growing needs of the East will not be met. Only a limited number of resources can be added directly into the Wasatch Front due to airshed restrictions. Increased transmission capability is needed to meet growing loads.

PORTFOLIO CATEGORIES

To explore a broad range of possible resource mixes, portfolios were first developed in three different portfolio categories: thermal, alternative technology and transmission. The different portfolio categories can be compared to learn operational differences based on resource type under varying assumptions. The following section discusses each category in more detail.

Portfolio Category: Thermal
Portfolios in the thermal category contain a mix of coal and natural gas additions. There are four subcategories of thermal portfolios: Gas/Coal, Coal/Gas, All Gas, and PacifiCorp Build. Each subcategory contains individual portfolios that are used to test the timing and size of resource additions. Below are brief descriptions of the each subcategory, and a listing of all portfolios that were developed in each subcategory:

Gas/Coal
This subcategory includes wide ranging portfolios with one or more natural gas plant additions in the early years and a coal fired plant in Utah or Wyoming in later years. In this and other portfolios peaking units are added as required to bring capacity up to required margin levels.

Portfolios contained within this subcategory include Gas/Coal I, Gas/Coal I – 10%, Gas/Coal II, Gas/Coal III, Wyoming Coal, and Peakers.

Coal/Gas
This subcategory also includes wide ranging portfolios however timing of the Coal and Natural Gas base load units are switched. These cases install a Utah area coal plant addition in the early years and combined cycle natural gas plants in later years. Portfolios contained within this subcategory include Coal/Gas I, Coal/Gas II, Coal/Gas III, and Coal/Gas III – 10%.

All Natural Gas
The all natural gas portfolios are similar to the Gas/Coal and Coal/Gas portfolios listed above, except a base load coal plant is replaced with a combined cycle natural gas plant. Therefore, in this subcategory, the primary fuel in all new thermal resources is natural gas.

Portfolios contained within this subcategory include All Gas I, All Gas II, and All Gas II – 10%.

PacifiCorp Build
This subcategory places additional emphasis on construction. The contracts present in other portfolios are replaced with PacifiCorp constructed assets. These portfolios can be compared to those with contracts to determine the difference in costs to build as well as the level of risk associated with building.

Portfolios contained within this subcategory include PacifiCorp Build I, PacifiCorp Build II, and PacifiCorp Build II – 10%

Benefits, Uncertainties and Issues
There are benefits, uncertainties, and issues associated with portfolios in the thermal category. One benefit is the good prospects for siting and licensing generation, since PacifiCorp currently owns or controls existing thermal generation sites with room for expansion. Another benefit to the thermal portfolios is that PacifiCorp can make use of existing transmission corridors. Finally, PacifiCorp currently has experience with building, owning and operating thermal facilities.

One uncertainty associated with thermal portfolios, and more specifically those thermal portfolios that contain coal additions, is the impact of future environmental legislation. The thermal portfolios with a large amount of combined-cycle or peaking plants are also faced with the uncertainty surrounding future natural gas price volatility.

Portfolio Category: Alternative Technology
The purpose of the Alternative Technology portfolios was to build portfolios that ultimately reduced the number of thermal plants in PacifiCorp's system and replace them with a combination of conservation and alternative technologies. This was accomplished by adding additional wind plants, over and above the wind that was developed in the Thermal Portfolios, in both the East and West control areas, as well as geothermal plants, fuel cells, CHP and additional DSM. The Load control program used in these portfolios is 30MW of new A/C load control program above that contained in all portfolios. Natural gas-fired plants (CCCTs and Peakers) were used to fill the energy balance and build the portfolio to the 15% planning margin.

Portfolios contained within this category include Alternative Technology I and Alternative Technology II. The differences between these two portfolios include the wind and peaker build patterns, as well as the replacement of a 1x1 CCCT in the West with a 2x1 CCCT. Tables 6.1 and 6.2 highlight the differences between the Alternative Technology I and Alternative Technology II portfolios.

Table 6.1 Alternative Technology I Portfolio Comparison for Build Pattern

Resource	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total (MW)
Wind East	-	-	600	-	-	-	-	120	-	-	720
Wind West	-	-	500	-	-	-	-	200	-	-	700
Peakers East	-	-	400	-	-	-	-	100	-	-	500
Peakers West	-	-	460	-	230	-	-	115	-	-	805
CCCT 1x1 Alb	-	-	-	-	-	-	-	-	285	-	285

Table 6.2 Alternative Technology II Portfolio Comparison for Build Pattern

Resource	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total (MW)
Wind East	-	-	-	200	-	200	-	200	-	120	720
Wind West	-	-	100	-	200	-	200	-	200	-	700
Peaker Mona	-	-	-	-	-	-	-	-	-	100	100
Peakers East	-	-	200	-	-	-	-	-	100	200	500
Peakers West	-	-	230	-	-	115	-	-	115	-	460
CCCT KFalls	-	-	-	510	-	-	-	-	-	-	510

As mentioned above, in all the initial portfolios the wind was modeled as a flat contract based on the Federal RPS. In the Alternative Technology portfolios, the additional wind (above the RPS level) is modeled as a PacifiCorp build option using historical wind plant data from sources near potential plant sites. By modeling the historical data some indication can be given of plant output variability, but this does not necessarily result in a fair representation of all the wind integration costs associated with firming electricity output and dispatching. Appendix L provides additional information regarding the costs associated with wind integration costs.

An important assumption to note in this portfolio is that the additional wind capacity (1,420 MW) added in this portfolio was not used in the calculation of the planning margin, therefore the additional capacity identified for the wind plants was over and above the 15% planning margin in this portfolio. This assumption was based on the fact that hourly wind output is not sufficiently reliable to count towards reserves. This is another conservative assumption. This conservative assumption is tested as a stress case in Chapter 7.

For the first five years of their operation, it is assumed that a Green Tag credit of $5/MWh accrues to PacifiCorp and its customers, as a result of adding the wind and geothermal plants. There is also an assumption that the Production Tax Credit (PTC) will be available at $18/MWh for the first ten years of the wind plant life and the first five years of the geothermal plant's life. These credits assumed for renewable resources, together with the differential provided by the assumed carbon tax costs inherent in other portfolios, combine to suggest significant cost savings for the Alternative Technology category that may or may not be realized, as is discussed in Appendix L.

Benefits, Uncertainties and Issues

There are benefits, uncertainties, and issues associated with the Alternative Technology portfolios. One of the most noticeable benefits is the reduction in emissions as a result of adding renewable and natural gas resources. There is also a benefit associated with further diversification of the resources in PacifiCorp's overall resource portfolio. Diversification mitigates fuel price risks and paradigm risks.

Some of the uncertainties identified in the Alternative Technology portfolios include:

- Fuel Cells are commercially proven technology that has been widely dispersed in the utility industry.
- There is both a high capital requirement and siting uncertainty for either PacifiCorp or a third party to build the level of wind required in these portfolios.
- Quality and location of potential wind sites, and associated transmission have not been fully identified.
- Specific DSM programs have not been identified or modeled for these portfolios.
- Integration costs associated with the wind plants need additional study, including regulating margin uncertainty, balancing charges for natural gas supply, and changes in integration costs as a function of wind capacity installed. Appendix L provides more detail on wind integration costs.
- The market clearing value of Green Tags and the annual availability of the Federal Production Tax Credit associated with the renewable resources are uncertain.

Portfolio Category: Transmission

The purpose of portfolios in this category is to concentrate on increasing system benefits by enhancing transmission capability to liquid and built markets as well as between PacifiCorp control areas and load centers. One of the main assumptions common to each portfolio in this category is that PacifiCorp builds and owns the transmission lines constructed, and does not include any participation or use of the line by third parties. It is assumed that such participation, though not modeled, would reduce costs of these portfolios.

There are two subcategories of thermal portfolios: East-West Transmission and Transmission to Asset Markets. Below are brief descriptions of the each subcategory, and a listing of all portfolios that were developed in each subcategory:

East-West Transmission

In these portfolios, a DC line was constructed from the Wasatch front to Malin, Oregon to allow better flexibility to transfer electricity from the East and West control areas. The new transmission line is a bi-directional, high-voltage DC line that was evaluated at two different sizes (1,000MW and 2,000 MW) to determine the most cost-effective option. Thermal resources are added to both the East and West control areas in each of these portfolios to meet energy requirements, and additional capacity was added to meet a 10% planning margin.

Portfolios contained within this subcategory include Transmission 1,000 MW DC and Transmission 2,000 MW DC.

Transmission to Asset Markets

This portfolio increases transmission access to markets with assets built by other parties. This portfolio assumes that by building and owning transmission, there will be additional opportunities for electricity purchase agreements tied to these assets. This portfolio concentrates on building lines in the eastern control area, specifically to the southern Nevada. As described in Chapter 1, there is currently a wave of new merchant generation construction in the WECC. This is concentrated in the Southwest. Transmission access to these assets in and through southern Nevada represents a significant opportunity to negotiate electricity purchase agreements with third parties that constructed plants in this area.

The only portfolio constructed in this subcategory is called Transmission to Asset Build Market.

Benefits, Uncertainties and Issues

There are benefits, uncertainties, and issues associated with portfolios in the transmission category. One benefit to constructing a DC line that connects the East and West control areas is that it would allow for greater system flexibility and greater utilization of existing resources. This could also result in a reduced planning margin. A benefit to increased transmission access to markets with assets built by other parties, is that it allows PacifiCorp to have access to low cost markets, and would reduce the capital requirement necessary to construct new plants.

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. Under RTO West, planning authority for an individual utility is also uncertain. Market design is still under discussion and will affect the economics of both transmission and generation investments. Third party utilization is an important factor in making the construction of new transmission cost-effective, and is still an uncertainty related to RTO West. There is also the issue related to constructing the DC line from the Wasatch Front to Malin, 625 miles of "right of way" would need to be negotiated to construct the line.

HYBRID PORTFOLIOS

After portfolios were developed and analyzed based on the portfolio categories, hybrids of these portfolios were developed using the best characteristics of the results of the existing portfolios. Five hybrid portfolios were created - Renewable, Diversified Portfolio I, Diversified Portfolio II, Diversified Portfolio III, and Diversified Portfolio IV. Below is a summary of how these portfolios were developed:

Renewable

This portfolio was developed using the Alternative Technology II portfolio as a starting point. To create the Renewable portfolio, the fuel cells, CHP, and DSM were removed from the Alternative Technology II portfolio, and replaced with a Mona 2x1 in 2009.

The Diversified Portfolios

These portfolios were developed using the top four thermal portfolios in each sub-category (Gas/Coal, Coal/Gas, All Gas, and PacifiCorp Build), and replacing the RPS flat $50/MWh contract with the gradual, profiled wind used in the Renewable and Alternative Technology II portfolios. A thermal contract was added to each of these portfolios to replace the lost capacity associated with the $50/MWh flat contract. Table 6.3 summarizes the new gradual, profiled wind used in all three diversified portfolios, as well as the thermal contract added to replace the capacity value given to the $50/MWh flat wind contract.

Table 6.3 RPS Replacement in Diversified Portfolios

Resource	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total (MW)
Wind East	-	-	-	200	-	200	-	200	-	120	720
Wind West	-	-	100	-	200	-	200	-	200	-	700
Thermal Contract East	-	-	25	25	25	0	25	25	25	25	175
Thermal Contract West	-	-	25	25	25	0	25	25	25	25	175

The three Diversified Portfolios were developed from the following initial portfolios:

- Diversified I was developed from Coal/Gas III
- Diversified II was developed from PacifiCorp Build I
- Diversified III was developed from Gas/Coal I
- Diversified IV was developed from All Gas II

Hybrid Portfolio Comparison

The following tables (Tables 6.4, 6.5, 6.6 , 6.7 and 6.8) identify key distinctions between the five hybrid portfolios.

Table 6.4 Diversified I Portfolio Comparison

	Diversified Portfolio I	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
East	Thermal contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12		123
	Wind (East - installed capacity in MW)				200		200		200		120	720
	Super Peak Contract	225				(225)						
	Coal Base Load (Hunter 4)					575						575
	CCCT (Mona)									480		480
	CCCT (Gadsby Repower)						510					510
	Peaker East (Mona)										200	200
	Reserve Peakers (East)			200							300	500
	East Market (Short Term)	500										500
West	Thermal contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)											
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2		22
	Wind (West - installed capacity in MW)			100		200		200		200		700
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			(500)							
	CCCT (Albany)				570							570
	Reserve Peakers (West)			230						230		460
	West Market (Short Term)	500										500
	Peaking Contract									100		100

Contract is 1 year longer than other portfolios.

First new base load is coal in 2008 vs. gas in 2007 for other portfolios.

Hunter and Mona base load units exchange places in this portfolio.

300

Table 6.5 Diversified II Portfolio Comparison

	Diversified Portfolio II	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
East	Thermal contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12		123
	Wind (East - installed capacity in MW)				200		200		200		120	720
	Super Peak Contract	225			(225)							
	Coal Base Load (Hunter 4)									575		575
	CCCT (Mona)				480							480
	CCCT (Gadsby Repower)						510					510
	Peakers (Mona)										200	200
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200						300		500
West	Thermal contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)											
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2		22
	Wind (West - installed capacity in MW)			100		200		200		200		
	CCCT (K. Falls)								255			
	3-Year Flat Off-Peak	500			(500)							
	CCCT (Albany)				570							570
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230							230	460

Peakers arrive 1 year earlier than other portfolios

Reserve peakers intalled 1 year later than other portfolios

1 on 1 CCCT replaces market purchases not found in other portfolios

Unlike other portfolios, no peaking contract in 2012

G1 12 3 22

Flat @ Mona monthly

Table 6.6Diversified III Portfolio Comparison

	Diversified Portfolio III	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
East	Thermal contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12		123
	Wind (East - installed capacity in MW)				200		200		200		120	720
	Super Peak Contract	225			(225)							
	Coal Base Load (Hunter 4)									575		575
	CCCT (Mona)						480					480
	CCCT (Gadsby Repower)				510							510
	Peakers (Mona)										200	200
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
West	Thermal contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)											
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2		22
	Wind (West - installed capacity in MW)			100		200		200		200		700
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			(500)							
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460

Gadsby and Mona additions switch between Diversified II & III

Smaller K-Falls CCCT replaces Albany CCCT in other portfolios.

Table 6.7 Diversified IV Portfolio Comparison

	Diversified Portfolio IV	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
East	Thermal contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (aMW added each year)	30	12	11	12	12	12	12	12	12		123
	Wind (East - installed capacity in MW)				200		200		200			600
	Wind (East - installed capacity in MW)										120	120
	Super Peak Contract	225				(225)						
	CCCT (Mona)						480			480		960
	CCCT (Gadsby Repower)					510						510
	Peaker East (Mona)										200	200
	Reserve Peakers (East)			200							300	500
	East Market (Short Term)	500										500
West	Thermal contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)											
	Class 2 DSM (aMW added each year)	5	2	2	2	2	2	2	2	2		22
	Wind (West - installed capacity in MW)									200		200
	Wind (West - installed capacity in MW)			100		200		200				500
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			(500)							
	CCCT (Albany)				570							570
	Reserve Peakers (West) (K. Falls)			230						230		460
	West Market (Short Term)	500										500
	Flat Contract Mid C									100		100

All new base-load units are gas-fired.

1/3 is modeled as Flat Firm so capacity is included

Table 6.8 Renewable Portfolio Comparison

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
East	Wind (installed capacity in MW)			93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (aMW added each year)	30	12	11	12	12	12	12	12	12		123
	Wind (East - installed capacity in MW)				200		200		200			600
	Wind (East - installed capacity in MW)										120	120
	Geothermal (East)				50							50
	Mona CCCT (2x1)						480					480
	Super Peak Contract	225			(225)							
	CCCT (Gadsby Repower)				510							510
	Reserve Peakers (East)			200						100	200	500
	East Market (Short Term)	500										500
	CCCT (Mona)									480		480
	Mona Peakers									100		100
West	Wind (installed capacity in MW)			93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)											
	Class 2 DSM (aMW added each year)	5	2	2	2	2	2	2	2	2		22
	Wind (West - installed capacity in MW)									200		200
	Geothermal (West)				50							50
	Wind (West - installed capacity in MW)			100		200		200				500
	Class 1 DSM (lc peak MW capability - UTM)											
	Class 2 DSM (aMW added each year)											
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			(500)							
	Reserve Peakers (West) (K. Falls)			230			115			115		460
	Peaking Contract								100			100
	West Market (Short Term)	500										500
	CCCT (K. Falls)				510							510

Portfolio resembles Diversified IV with additional wind and geothermal

Smaller peaking station than Diversified IV

SUMMARY

This Chapter has provided an overview of the different resource portfolios PacifiCorp has analyzed. The focus of Chapter 7 will be on reviewing the results of the portfolio analysis.

7. RESULTS

Previous Chapters described the process of simulating the marketplace and modeling various resource portfolios. This systematic and thorough methodology yielded a large body of results. This chapter discusses those results and analyzes them to identify their context and meaning. The most important of these create the foundation for the Action Plan detailed in Chapter 9.

Discussion of the results falls into four categories.

- Operational Results: This section presents the expected base-case costs of each portfolio. It summarizes the observations of simulated portfolio operations and explains why portfolios performed differently.
- Risk Analysis: The risk analysis summarizes portfolio variability due to the Stochastic Risks discussed in Chapter 3.
- Customer Impacts: The customer impacts section expresses portfolio results from the perspective of customers.
- Stress Testing: This section presents the findings associated with shocking or stressing different Scenario Risks.

OPERATIONAL RESULTS

The modeling process simulated expected portfolio operations. The results culminate in total portfolio costs, measured by Present Value Revenue Requirement (PVRR). The PVRR is a central measure of portfolio performance and a critical driver of resource selection in the Action Plan.

The modeling also captures a number of other important measures. These include cost sub-categories, which roll up into PVRR. Evaluating the cost components identifies relative strengths and weaknesses of different resource configurations. Explaining why different portfolio combinations result in different costs, the model finally provides a number of influential operating characteristics. Complete scorecards, summarizing the metrics for every portfolio, are provided in Appendix E.

PVRR

Determining portfolio Present Value Revenue Requirements was a principal objective of the modeling process. PVRR is the sum of year by year revenue requirements of a portfolio, discounted at an after-tax cost of capital to a common date. PVRR takes into account the time value of money such that different projections of costs of various timing and magnitude can be evaluated on a comparable basis[10]. Therefore, comparing PVRRs helps identify, on an expected present value basis, the least cost portfolio.

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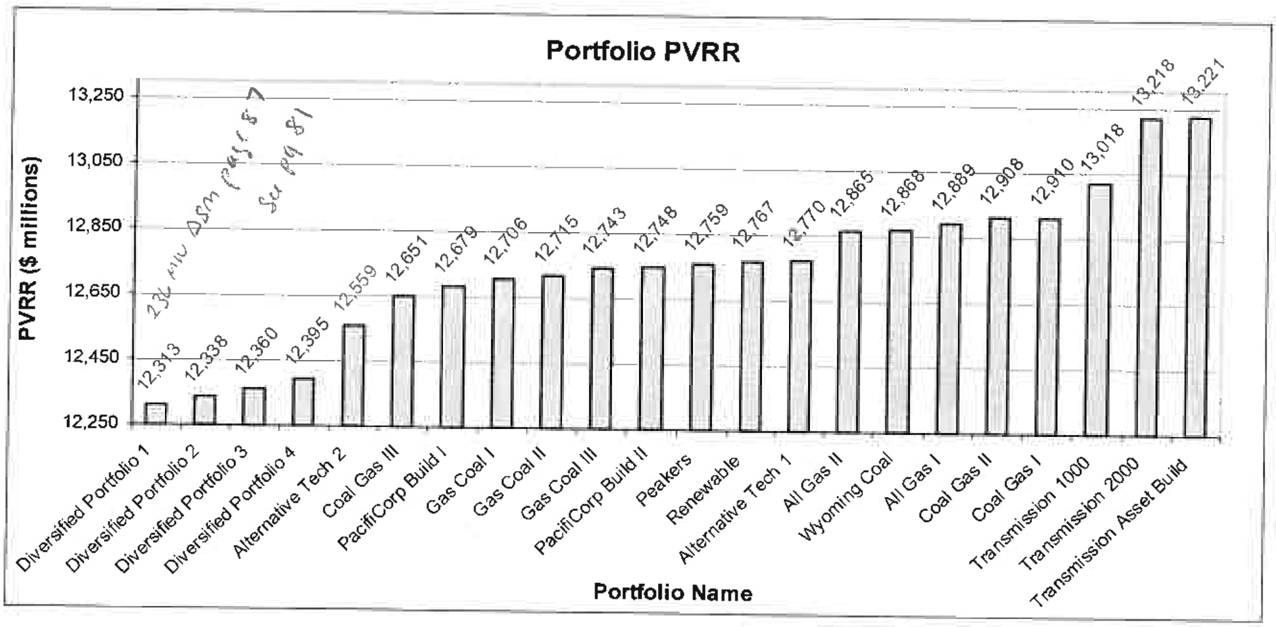
[10] Utah guidelines require PVRR to be expressed in terms of total resource costs. PVRR values provided within this chapter are based on total *utility* costs. Total resource costs can be derived by adding $81,384,458 to all PVRRs provided herein.

Figure 7.1 illustrates the PVRR for each of the major portfolios evaluated. Early portfolios were developed to test different resource attributes. Subsequent modifications eliminated undesirable characteristics. As portfolios improved, they moved from the right to the left, as seen in Figure 7.1. Such movement demonstrates the success of the optimization process discussed in Chapter 4. The information below summarizes portfolio PVRRs:

Figure 7.1 Portfolio PVRR Comparison



The top four portfolios, shown on the left of the graph, represent the best PVRRs of the group and the conclusion of the refinement process. The remainder of this chapter focuses on these four. With a large concentration of renewable resources, the results of the Renewable portfolio are also of interest. Therefore, subsequent analysis includes frequent references to this Renewable portfolio.

Key Observations on the top four portfolios include:

- Diversified portfolio I has the lowest PVRR of the portfolios studied.
- In relative terms, Diversified Portfolios I - IV provided similar PVRRs. Among the five hybrid portfolios (Diversified I-IV and Renewable), differences ranged from 0.2% to 3.6% above the Diversified I.
- In absolute terms, Diversified Portfolios II - IV differed from Diversified I by $25m to $82m. Renewable exceeded Diversified I by $454m.

Portfolio Scorecard

For convenient reference, model output is summarized on Portfolio Scorecards. Table 7.1 contains the Scorecard for the Renewable and four Diversified Portfolios. Scorecards include the following measures:

- PVRR and capital costs
- Emissions
- Market sales and purchases
- Existing and new unit capacity factors
- System transfers between East and West

The analysis and related discussion in this section frequently refer to this scorecard. Additional scorecards found in Appendix E summarize the alternative portfolios studied as well as the results of numerous stress tests.

Table 7.1 Hybrid Portfolio Scorecard

VALUE MEASURE

	Diversified I	Diversified II	Diversified III	Diversified IV	Renewable
Present Value Rev. Req't (20 Year $000)	**12,313,159**	**12,337,893**	**12,360,185**	**12,395,185**	**12,767,268**
Percent Greater Than Lowest NPV	0.000%	0.201%	0.382%	0.666%	3.688%
Incremental Net Variable Power Cost	9,779,027	9,841,314	9,992,809	10,456,417	10,576,052
Incremental Real Levelized Fixed Cost	2,343,907	2,306,354	2,177,151	1,748,542	2,000,991
DSM Real Levelized	190,225	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,643	2,831	2,644	2,077	2,237
Emissions (2004-2023 PVRR $000)	**21,750**	**32,826**	**(7,237)**	**(122,127)**	**(138,826)**
CO_2 (thousand tons 2009-2023)	847,919	851,850	841,248	811,477	807,598
CO_2 (% of cap)	105%	105%	104%	100%	100%
SO_2 (thousand tons 2009-2023)	652	655	654	645	644
SO_2 (% of cap)	63%	63%	63%	62%	62%
NO_x (thousand tons 2009-2023)	1,046	1,049	1,047	1,036	1,035
NO_x (% of cap)	102%	102%	102%	101%	101%
Hg (thousand tons 2009-2023)	0.0038	0.0036	0.0036	0.0024	0.0024
Hg (% of cap)	69%	66%	66%	44%	44%
Market Purchases (10 Year)					
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%	0.1%
PAC East Average MW	10	9	9	11	9
PAC West (% of load)	1.1%	1.1%	1.1%	1.1%	1.1%
PAC West Average MW	80	80	83	80	82
Market Sales					
PAC East (% of owned Generation)	7.1%	6.9%	7.0%	6.7%	6.9%
PAC East Average MW	323	313	316	300	310
PAC West (% of owned Generation)	11.0%	10.7%	10.7%	10.8%	10.7%
PAC West Average MW	304	304	296	304	300
Unit Capacity Factors (2014)					
Existing Coal East	84.3%	84.6%	84.2%	86.2%	86.5%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.3%	3.0%	3.5%	4.2%	3.6%
IRP CCCT East	47.8%	47.0%	47.5%	63.3%	62.7%
IRP Coal East	91.0%	91.0%	91.0%		
IRP Peaker East	4.6%	4.5%	5.0%	5.5%	5.2%
Existing CCCT West	34.2%	31.5%	35.2%	37.8%	36.9%
Existing Coal West	86.0%	86.2%	86.1%	86.9%	87.0%
Existing Other West	90.9%	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	77.4%	77.2%	78.5%	81.8%	82.2%
IRP Peaker West	9.0%	11.9%	10.1%	10.1%	9.6%
East West Transfers (MWHs)					
2004 East-West Transfer	799,978	801,435	799,978	801,435	799,126
2014 East-West Transfer	1,077,393	1,124,739	1,083,438	766,831	790,797
Percent Increase/Decrease over 2004	135%	140%	135%	96%	99%
2004 West-East Transfer	1,901,936	1,899,981	1,901,936	1,899,981	1,902,380
2014 West-East Transfer	1,303,125	1,332,926	1,293,016	1,588,166	1,554,709
Percent Increase/Decrease over 2004	69%	70%	68%	84%	82%

Cost Categories

Evaluating the components of PVRR provides insight into portfolio performance. These evaluations help explain the results observed and aids the development of an Action Plan.

Fixed vs. Variable Costs

PVRR is comprised of both fixed and variable cost elements. Operational simulation demonstrates that portfolios with lower PVRRs tended to exchange higher fixed costs in return for lower variable costs.

For example, the high fixed costs of Diversified I can be attributed to the early installation of a coal plant with associated transmission. Realized the earliest, these fixed costs have greater present values than other portfolios. Offsetting the fixed costs, the variable costs savings of the early coal (compared to natural gas) have a substantial present value advantage over the other portfolios. Figures 7.2 and 7.3 illustrate this tradeoff.

In contrast, Diversified IV enjoys lower fixed costs. It substitutes less capital-intensive natural gas-fired base load units for coal. With reduced dependence on high fixed cost resources, the portfolio relies on higher variable cost resources. The greater dependence on high priced natural gas drives up variable costs substantially. A similar tradeoff occurs with the Renewable portfolio. Under this configuration large renewable contracts (reported as variable costs) replace the capital requirements of a base load unit.

Therefore, among the final portfolios, additional fixed cost investments appear to provide a moderate benefit over variable cost investments. This observation was consistent over the final portfolios as well as the other major portfolios discussed earlier.

Figure 7.2 Real Levelized Fixed Costs

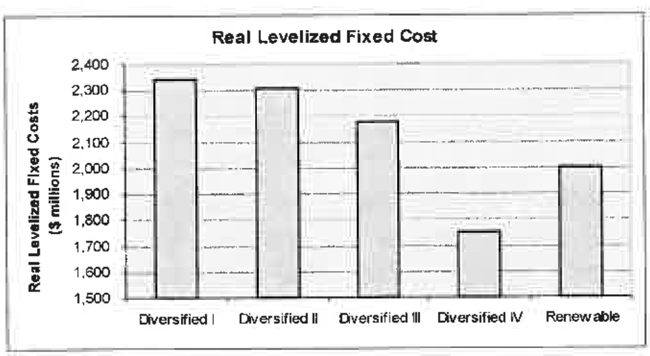
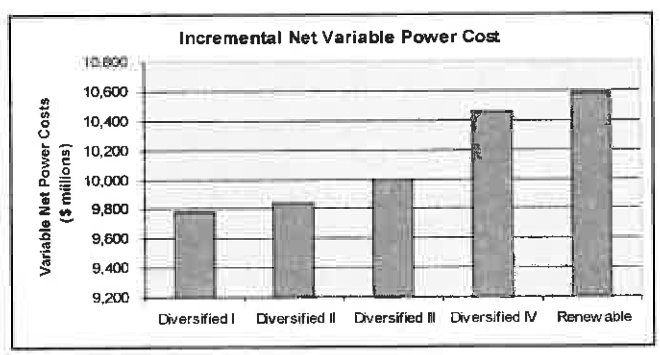


Figure 7.3 Inc. Net Variable Power Costs



Note: The above figures are plotted on a different scale.

Key Observations

- The Diversified I portfolio has the greatest real levelized fixed cost and the least incremental net variable cost of the final portfolios.
- Conversely, Diversified IV has the lowest real levelized fixed costs and second highest net variable electricity costs among the final portfolios.

- Variable costs between Diversified I and Diversified IV differ by $677m. Fixed costs differ by $595m.

Elements of Variable Costs

Variable costs, as traditionally defined, consist of many elements, some of which are individually detailed in other categories of the scorecard. The categories include: fuel costs, variable O&M, unit start-up costs, emissions costs or credits, spot market sales and purchases, and variable long term contract costs. Variable cost characteristics differ, depending on the type and timing of resource installations.

Over the 20-year study period, the variable elements of each portfolio compare to each other as shown in Table 7.2.

Table 7.2 Variable Cost Elements

Variable Cost Elements ($000)	Diversified I	Diversified II	Diversified III	Diversified IV	Renewable
Total Fuel Cost	7,874,230	8,325,842	8,009,694	8,426,120	8,479,704
Total Variable O&M Cost	620,865	651,759	634,924	653,349	651,144
Total Emissions Cost	21,750	32,826	(7,237)	(122,127)	(138,826
Total Start-up Cost	70,443	69,883	69,868	69,825	69,138
Variable Contract Cost	3,612,131	3,171,451	3,611,273	3,639,705	3,816,778
Sales*	(2,747,817)	(2,726,240)	(2,680,971)	(2,609,685)	(2,625,092
Purchases*	695,734	684,103	723,567	767,541	753,957
Renewable Adjustment**	(368,310)	(368,310)	(368,310)	(368,310)	(430,751
Total	9,779,027	9,841,314	9,992,809	10,456,417	10,576,052

*Sales and Purchases refer to spot sales and purchases

**Includes PTC, Green Tag, and Integration Costs

% Change from Diversified I	Diversified I	Diversified II	Diversified III	Diversified IV	Renewable
Total Fuel Cost	--	5.7%	1.7%	7.0%	7.7%
Total Variable O&M Cost	--	5.0%	2.3%	5.2%	4.9%
Total Emissions Cost	--	50.9%	-133.3%	-661.5%	-738.3%
Total Start-up Cost	--	-0.8%	-0.8%	-0.9%	-1.9%
Variable Contract Cost	--	-12.2%	-0.02%	0.8%	5.7%
Sales*	--	-0.8%	-2.4%	-5.0%	-4.5%
Purchases*	--	-1.7%	4.0%	10.3%	8.4%
Renewable Adjustment**	--	--	--	--	17.0%

Fuel Costs: Fuel costs make up the greatest portion of variable costs in every portfolio. Diversified I has the lowest fuel cost. With a coal unit serving as the first base-load addition, high-priced natural gas provides a smaller portion of the portfolio's fuel requirements. The difference in fuel exposure is a key advantage of this portfolio.

Other portfolios incur greater fuel costs and have greater natural gas exposure. Diversified III fuel costs are 1.7% greater. Diversified III similarly adds a coal unit. However, the coal unit does not go on line until 2012. Diversified III in turn leads Diversified II which has much greater fuel expense due to the late introduction of Hunter 4 and replacement of West contracts (consuming no fuel) with built resources (which do).

It is important to note that, despite its name, the Renewable portfolio contains substantial additions of fossil generation. Like Diversified IV, the Renewable portfolio does not include coal and features the early installation of a base-load natural gas unit. However, Renewable portfolio units operate at higher unit capacity factors than Diversified IV. Accordingly, the Renewable portfolio incurs the greatest fuel expenses.

Emission Costs: Emission charges represent a smaller component of total variable costs. Emissions costs are the lowest for the Renewable portfolio. With emissions below assumed caps these 'costs' result in credits to system costs. Conversely, Diversified II features the highest emissions costs.

The distinction between Diversified II and III arises from the use of contract purchases. Diversified III assumes a greater level of variable contract purchases ($3.6 billion vs. $3.1 billion). Regionally, the same level of emissions occurs regardless of who generates the energy. However, a difference appears in this cost category because PacifiCorp incurs an expense for emissions associated with its proprietary generation. Such emissions count against PacifiCorp's cap levels. If another party generates, the emissions would count towards their emissions cap and are captured in forward prices (falling into a different cost category). Independent of contract purchases, portfolios including new coal, installed before 2012, suffer from notably increased CO_2 and Hg emission costs.

Under base case assumptions emissions represented a smaller cost category. As shown in later stress tests, this could change. The outcome of pending environmental legislation will play a major role in determining the optimal fuel and resource mix. Until the legislation is clarified, it remains a substantial risk factor.

Start-Up Costs: Start-Up Costs are insignificant to the overall total variable costs for the portfolios but give insight into differences in unit operations between portfolio. Operations in Diversified I require more frequent unit starts to balance the system.

Variable Contract Costs: These costs include long-term purchases like contract renewals and PPAs. Variable contract costs represent the second largest category of variable costs. Here, Diversified II stands out. Contract costs fall approximately 12%, since built resources replace the West contracts found in other portfolios.

Diversified I and Diversified III include similar contracts and costs. The Renewable portfolio has variable contract costs 5.0% greater than Diversified I and Diversified III due to a $50/MWh, flat renewable contract not present in the other portfolios. Strongly influencing its PVRR ranking, the fixed price contract is one of the key features of this portfolio.

Sales & Purchases: This category includes the PVRR of spot sales and purchases pursuant to the model dispatch logic.[11] Spot market sale revenues increase in the years a large resource is added. At that point, sales rise over portfolios with smaller, more flexible units. For example, Diversified I adds a large coal plant in 2008. In 2008 sales rise significantly.

[11] Within the IRP, spot Sales and Purchases include all balancing transactions, which occur outside of existing long-term contracts.

Figures 7.4 and 7.5 plot spot market sales for the West and East markets. On the West plot, Diversified III sales are represented by the first line followed by Diversified II and Diversified I. The Diversified IV and Renewable portfolio were not shown, but present similar profiles. All portfolios follow a similar pattern with a plateau at the 250 MW level. Recall from Chapter 5 that market access in the West is restricted to 250 MW at COB and 250 MW at Mid-Columbia. At the plateau, market prices cause one point to run at the maximum capacity while the other remains at 0 MW. During approximately 30-35% of all hours in 2014, market sales reach a maximum capacity of 500 MW. Conversely, for about 12% of all hours, there are no West market sales.

In the East, market sales reach a maximum of 500 MW for 22% of all hours for the Diversified portfolios. As shown in Figure 7.4 all portfolios have no sales for 5% of all hours. Observed in Figure 7.5, market sales plateau in the East for a significant period of time. The plateau occurs at 350 MW. This is the limit to PacifiCorp's existing firm transmission rights. Additional sales incur substantial, short-term transmission procurement charges. Thus, the model economically restricts additional sales to a more limited period of time. Additional information regarding market access can be found in Chapter 5 and Appendix J.

Figure 7.4 Spot Market Sales - West

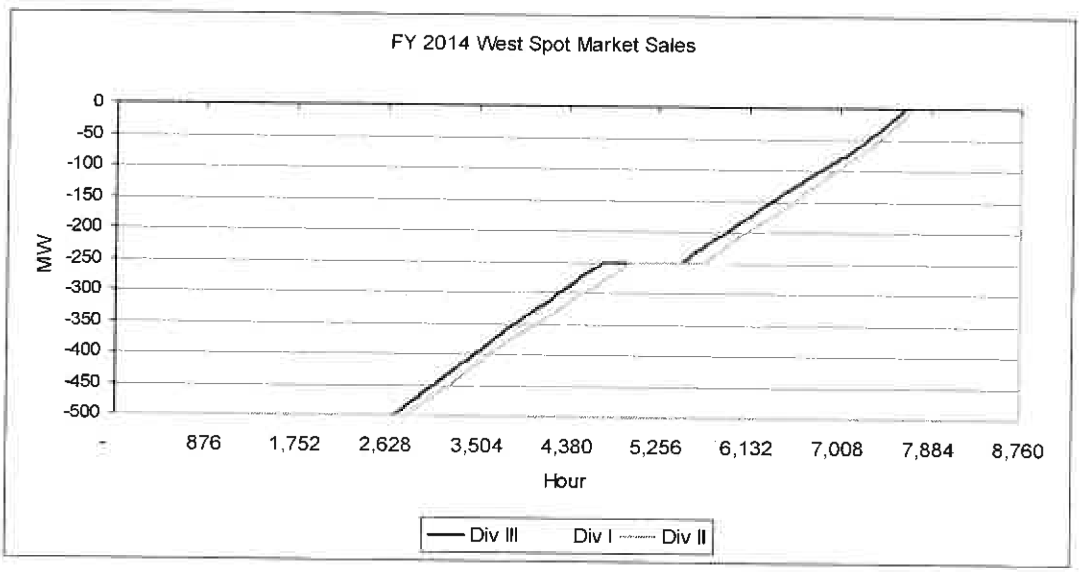
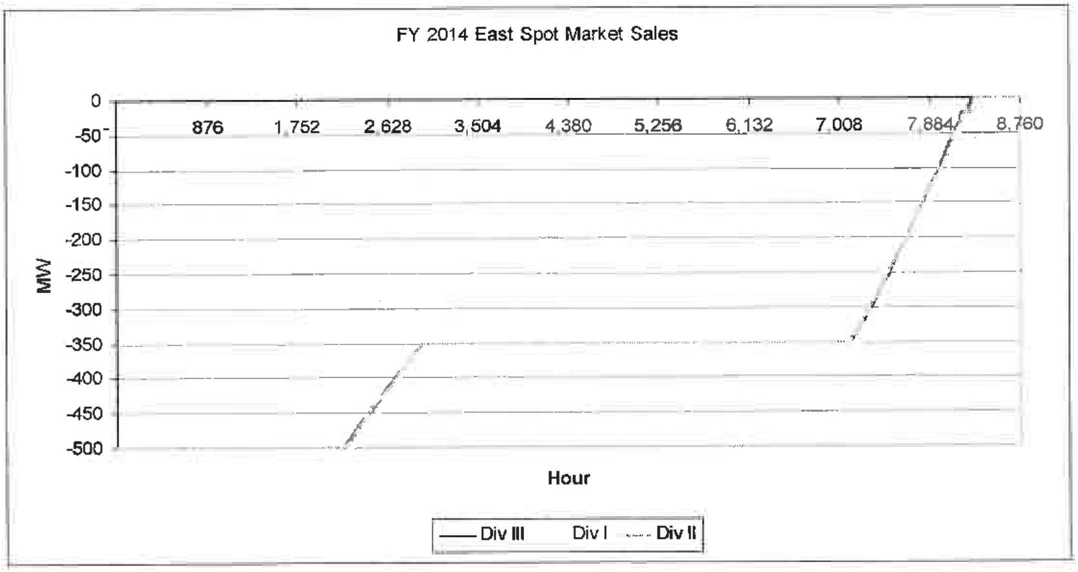


Figure 7.5 Spot Market Sales - East



Figures 7.6 and 7.7 illustrate spot market purchases for the three portfolios. Market purchases decrease with each addition of capacity.

Of the other Diversified Portfolios, Diversified II adds the most new resources. It also displays the fewest market purchases. The resources of Diversified II operate more flexibly than the contract purchases of I and III. The physical resources better adjust to variable system demands than the flat contracts.

West FY 2014 purchases are greater than the East with 2-5% of all hours purchasing the maximum available, 500 MW. Diversified II and III require the most market purchases. Diversified I requires the least. Between 60-70% of all hours, West spot market purchases decrease to 0 MW. The very low reliance on market purchases in the East is displayed in Figure 7.7 where all portfolios show East market purchases for fewer than 5% of all hours in FY 2014.

Figure 7.6 Spot Market Purchases - West

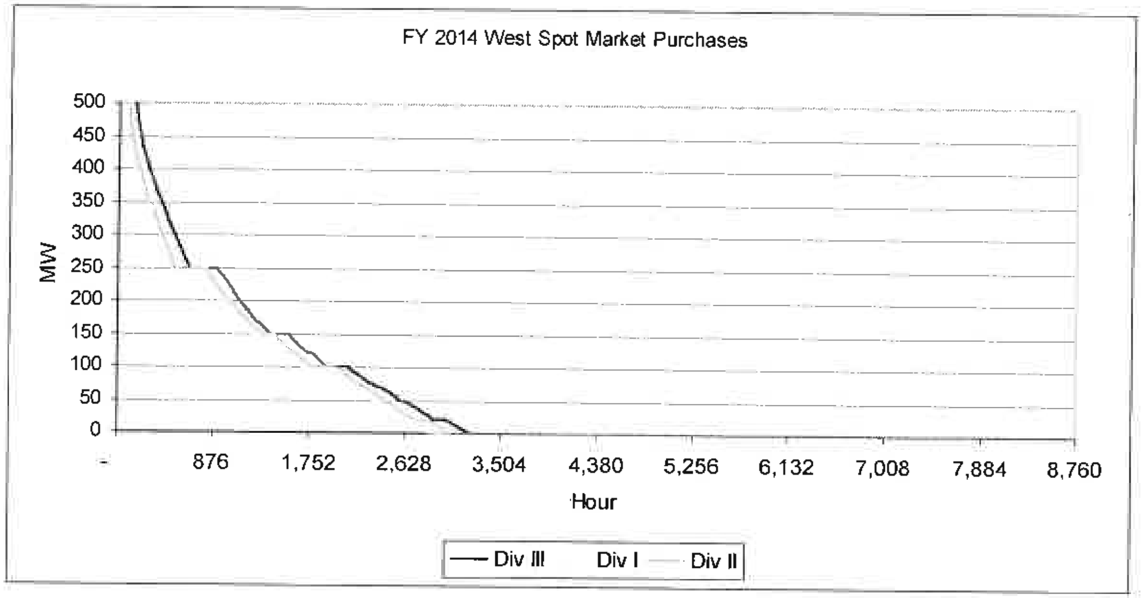
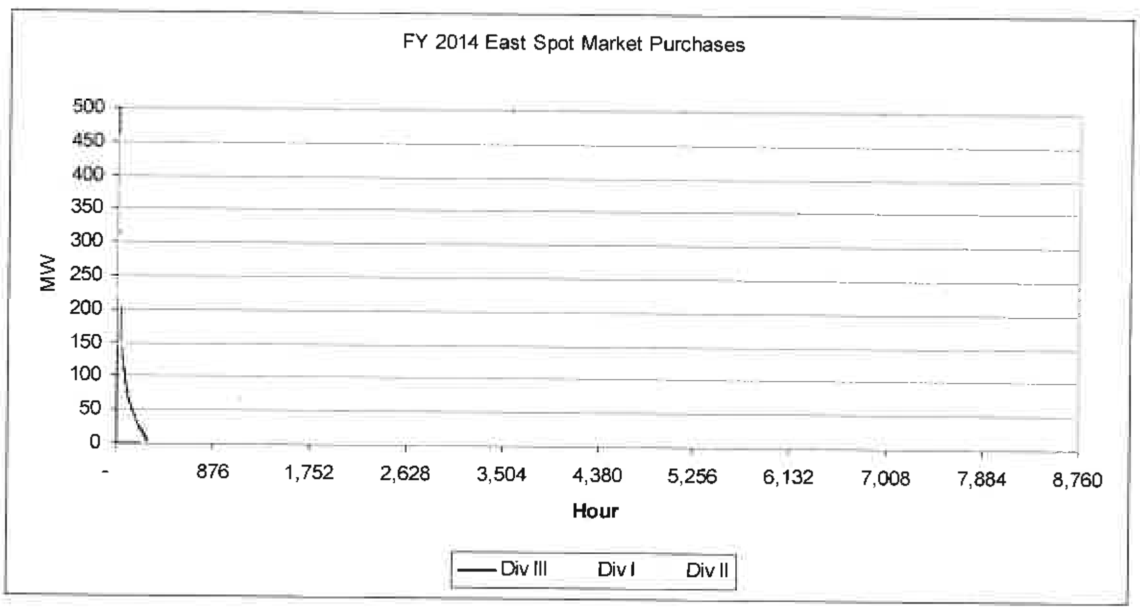


Figure 7.7 Spot Market Purchases - East



The purchase and sale profiles demonstrated above consistently lead to superior PVRR performance. In an attempt to reduce market sales, portfolios substituting base load elements with peakers were constructed. Peakers provide more operating flexibility at higher marginal costs. The test produced the intended drop in market sales. However, the resulting portfolios relied more heavily on market purchases. One market exposure (high sales) was merely traded for another (high purchases). Furthermore, the purchases combined with higher operating costs caused PVRR to increase.

Other Operational Measures

Cost measures are important means of evaluating portfolio performance. In addition to costs, Capacity Utilization factors and System Transfers help explain the operations of each portfolio.

Capacity Utilization

Capacity utilization factors provide valuable insight into the appropriateness of resource additions. Poor utilization factors may imply unnecessary capacity costs. They also act as an indicator of stranded power. The measure was particularly useful in the portfolio development process where extreme values signaled a need for resource changes. The final portfolios are the products of iterative improvements driven, in part, by this metric. Accordingly, they generally display favorable utilization factors.

The four Diversified portfolios show very similar unit behavior by 2014. Existing fleet performance by resource type in the East remains high in 2014 for all portfolios. Capacity factors for existing West CCCTs decreases between 32% and 38%. New coal units run at a maximum availability of 91%. New CCCT units operate at 47% to 82% capacity factors. New Peaking units perform as expected - around the 5% to 12% capacity factor level. Refer to Appendix J for a discussion of the screening curve used to assign different resources to different load profiles.

With high capacity factors, there are no obvious signs of new units merely displacing existing units or adding risk by creating a long market position. Furthermore, consistent with the strategy of obtaining resources only to serve load, high utilization factors are evidence that generation is not being added for merchant purposes.

System Transfers

With the exception of the Renewable and Diversified IV portfolios, East to West transfers increase by 135-140% between 2004 and 2014. The Renewable portfolio's West to East transfers decrease. West to East transfers decrease by approximately 70% for Diversified Portfolios I-III, and 82 to 84% for the Renewable and Diversified IV Portfolios. This suggests the system becomes more generally balanced over time with the introduction of Diversified Portfolios I, II and III.

Operational Results - General Conclusions

Portfolio comparisons illustrate an exchange between fixed and variable costs. This exchange is intuitive. Higher fixed and capital cost investments tend to result in lower variable cost resources. Such an exchange, though moderate, appeared to positively impact PVRR.

PVRR differences between final portfolios are heavily influenced by differences in variable costs. Diversified I has the lowest variable costs. Low fuel and variable O&M cost advantages slightly outweigh higher contract purchase costs. The early installation of a coal plant in this portfolio moderately increases fixed costs, but, relative to the other portfolios, greatly reduces fuel and operating expenses for the portfolio between years 2008 and 2011. The timing of the base load unit addition (2008 vs. 2007) also appears to benefit costs.

Superior portfolios tend to require substantial market sales. Built to a 15% planning margin over forecast peak load, top portfolios include substantial balancing requirements in non-peak periods. Attempts to restrict market exposure resulted in poorer PVRRs.

While each portfolio configuration affect cost categories differently, tradeoffs between categories occurred and mollified the overall impact. Changing portfolios to reduce a specific cost can be likened to squeezing a balloon. As a balloon (or cost) is squeezed in one area, other areas of the balloon push outwards. For example, the lower fuel costs associated with Diversified III tended to be offset by higher Variable Contract Costs. Similarly, higher fixed cost investments in Diversified I tended to reduce variable cost exposures.

Although portfolios feature differing resources and installation timing, they tended to converge with respect to costs. This is an expected outcome of an iterative portfolio development process. Portfolios were iteratively improved and collectively approached least cost configurations.

East – West Cost Segmentation

Portfolio simulations include the physical transmission limitations between control areas. Accordingly, resources generally fall into east and west portfolio sub-categories. Table 7.3 details the costs associated with each sub-category.

Incremental PVRR

Portfolio costs tend to follow a 60x40 split between the east and west sub-categories. This is consistent among all of the final portfolios with 60 percent of the costs associated with the East sub-category.

Net Variable Power Cost

Discussed above, Net Variable Power Costs are a significant component of PVRR. Among the sub-categories of each portfolio, greater cost parity was observed. The Net Variable Power Costs tending to be equally divided between the two portfolios.

Capital Costs

Table 7.3 demonstrates that the East to West ratio is greater with respect to capital costs. Portfolio sub-categories tended to demonstrate a 70x30 split. Combined with more equivalent division of net variable costs, the capital costs contribute to the observed total PVRR 60x40 split.

Table 7.3 East – West Cost Breakdown

		Values					Percentages			
		Renewable	Diversified Portfolio I	Diversified Portfolio II	Diversified Portfolio III	Diversified Portfolio IV	Renewable	Diversified Portfolio I	Diversified Portfolio II	Diversified Portfolio III
	Portfolio Incremental PVRR	**12,767,268**	**12,313,159**	**12,337,893**	**12,360,135**	**12,395,185**	-	-	-	-
New Resources Only	**Incremental PVRR** [1]	6,416,083	6,383,121	6,336,750	6,291,241	6,229,861				
	PAC West	2,675,331	2,669,362	2,651,665	2,592,933	2,680,755	42%	42%	42%	41%
	PAC East	3,740,752	3,713,759	3,685,085	3,698,308	3,549,106	58%	58%	58%	59%
	Net Variable Power Cost	4,224,853	3,848,975	3,840,157	3,923,851	4,291,080				
	PAC West	1,942,885	2,048,495	1,915,021	1,970,701	2,075,264	46%	53%	50%	50%
	PAC East	2,281,967	1,800,480	1,925,136	1,953,150	2,215,816	54%	47%	50%	50%
	Real Levelized Fixed Cost	2,001,005	2,343,921	2,306,368	2,177,165	1,748,556				
	PAC West	713,423	601,844	717,621	603,209	586,469	36%	26%	31%	28%
	PAC East	1,287,582	1,742,077	1,588,746	1,573,956	1,162,087	64%	74%	69%	72%
	DSM Real Levelized [2]	190,225	190,225	190,225	190,225	190,225				
	PAC West	19,023	19,023	19,023	19,023	19,023	10%	10%	10%	10%
	PAC East	171,203	171,203	171,203	171,203	171,203	90%	90%	90%	90%
	Capital Costs	2,262	2,643	2,831	2,644	2,077				
	PAC West	813	610	797	611	610	36%	23%	28%	23%
	PAC East	1,450	2,034	2,034	2,034	1,467	64%	77%	72%	77%
	Total MW Additions	6,006	5,365	5,320	5,305	5,270				
	PAC West	2,593	2,205	2,160	2,145	2,205	43%	41%	41%	40%
	PAC East	3,413	3,160	3,160	3,160	3,065	57%	59%	59%	60%

1. Incremental PVRR of New Resources = Net Variable Power Cost + Real Levelized Fixed Cost - DSM Real Levelized
2. No costs for Oregon Trust DSM are used in this calculation

RISK ANALYSIS

Expressing each portfolio in terms of deterministic PVRR conveys just one dimension of portfolio performance. The risk of each portfolio represents another key dimension. This section provides five risk measures for comparison:

- 95th Percentile
- 5th Percentile
- $95^{th} - 5^{th}$ Percentile
- Coefficient of Variation
- Mean of Tail

Each measure provides a different perspective on the risk profile of the final portfolios. Taken in aggregate, they help establish portfolio rankings.

While it is helpful to evaluate individual portfolio risks, those risk measures alone do not convey the cost effectiveness of investments needed to achieve (or mitigate) them. Therefore, this section also evaluates the tradeoffs between investment and risk.

Risk Measures

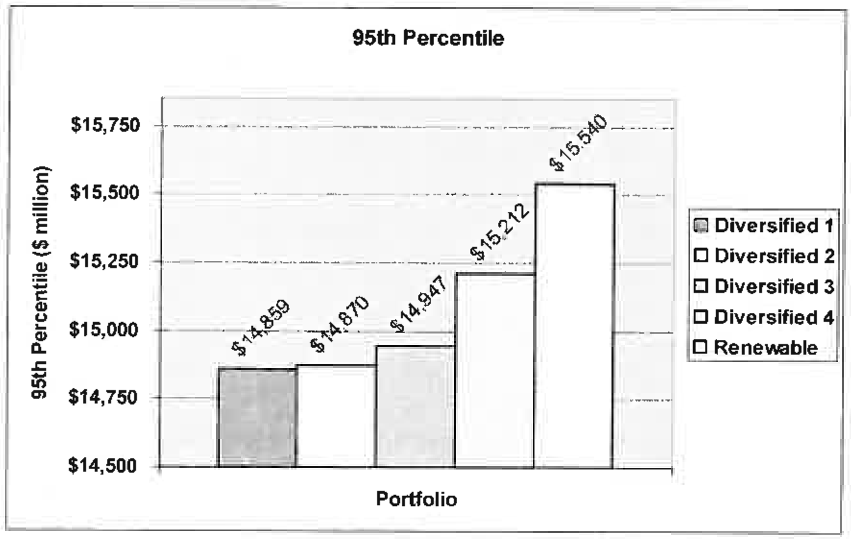
The following risk measures define the risk profile of the final portfolios and allow comparisons between them. In addition to defining the measure and showing the model results, this section details the limitations of each.

95th Percentile

This measure allows for high-risk case comparisons between portfolios. Ninety-five percent of the simulated PVRR observations occurred below this point. Given the asymmetrical distribution of simulated outcomes, the 95th percentile provides an efficient risk representation.

Decisions based on this metric must be made with some caution. While the 95th percentile helps define the high side of potential PVRR outcomes, it doesn't provide insight into the overall variability of the portfolio.

Figure 7.8 95th Percentile



Diversified I has the lowest 95th percentile. Thus, according to this measure, its future is expected to entail a lower likelihood of high PVRR outcomes. Renewable exceeds the next nearest portfolio by $328m.

High PVRR iterations tend to coincide with high loads and natural gas prices. A greater sensitivity to natural gas price fluctuations makes Diversified IV prone to high PVRR outcomes during these scenarios. The Renewable Portfolio reliance on natural gas combined with an overall higher cost structure appears to be a leading cause for the divergence in costs at the 95th percentile.

Relative to Diversified I, the Diversified IV portfolio relies more heavily on natural gas fired generation. From the standpoint of PVRR, the dependence on natural gas fired generation is exacerbated by an earlier installation time line. New natural gas-fired base load units arrive earlier in the Diversified IV Portfolio than the Diversified I Portfolio. Table 7.4 illustrates the comparative build-up of natural gas generation in Diversified I and Diversified IV.

Table 7.4 Natural Gas Capacity Comparison

		Natural gas Base Load MW	Peakers MW
Diversified IV	Installed through 2008	1,080	430
	Installed through 2014	2,040	1,160
Diversified I	Installed through 2008	570	430
	Installed through 2014	1,560	1,160

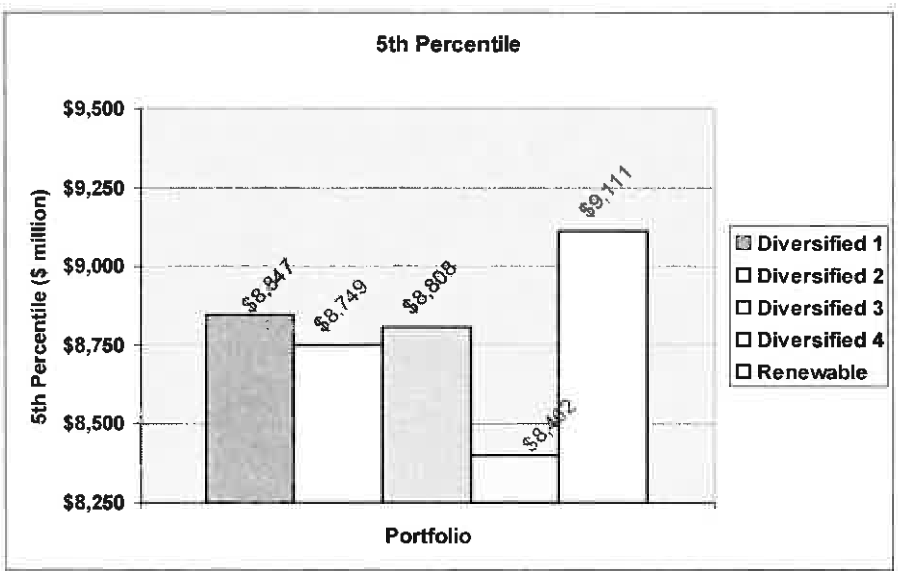
Furthermore, the Diversified I, II and III portfolios include a coal base load unit installed no later than in 2014. Though the impact in Diversified II and III is somewhat diminished by discounting, this common element tends to cause their 95th percentiles to converge at a point lower than the Renewable and Diversified IV portfolios.

Other than this exception, the final portfolios are tightly clustered. Given the diversity of modeling inputs and time horizon of the study, it could be argued that the 95th percentiles of the portfolios are statistically indistinguishable.

5th Percentile

Five percent of the simulated observations occurred below this point. Since low PVRRs are generally preferred, this measure of risk helps identify a reasonable approximation of best-case expectations. Like the preceding measures, lower values are generally preferred. They illustrate the reasonable extreme of best-case outcomes. This measure is of particular interest when interpreting the previously discussed risk metrics.

Figure 7.9 5th Percentile



Low PVRR cases (like the 5th percentile) tend to feature low load trajectories and moderate to high natural gas prices. The Diversified IV Portfolio demonstrated the most favorable, best-case results under these conditions. With only natural gas-fired base load capacity, the portfolio enjoys lower fixed and capital costs. Under lower loads, Diversified IV also appears to avoid the expense of its higher market purchases originally observed in Table 7.1.

The Renewable portfolio demonstrates the highest results under this metric. Observed in Chapters 3 and 6, the Renewable portfolio features a large, fixed-price, must-take renewable contract. This contract appears to increase costs at the 5th percentile by contributing to a higher overall cost structure.

Moderate natural gas prices converging with lower loads appear to create favorable conditions for market sales for all portfolios. Intuitively, natural gas dependent Diversified IV should benefit the least from such sales. The greater absolute fuel costs of Diversified IV appear to be partially offset as this portfolio benefits from monetizing the correspondingly higher dollar value of the spark spread.

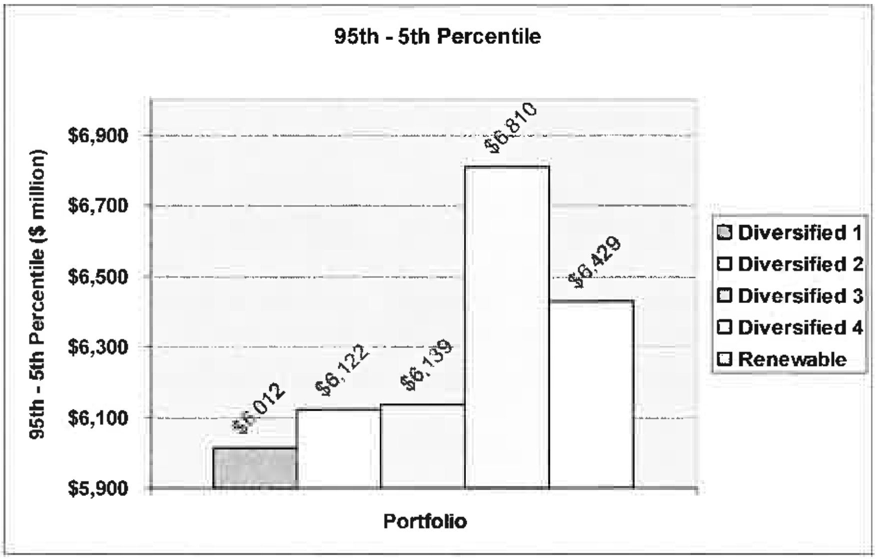
The Diversified I portfolio includes the early installation of a coal plant. With the large capital costs subjected to fewer years of discounting, this portfolio element causes the 5th percentile of Diversified I to drift upwards.

95th – 5th Percentile

This value is another measure of risk. The measure equals the difference between the 5th percentile and the 95th percentile of PVRR. Nine out of ten iterations fell within this range. Thus, it represents a reasonable range of expected outcomes for each portfolio. The larger this range, the greater the risk associated with each portfolio.

The 95th – 5th measure defines the reasonable range of expected outcomes. However, decisions based on it should be made with some caution. Comparisons based upon this risk measure may be confusing among portfolios with significantly different means and/or 5th percentiles.

Figure 7.10 95th – 5th Percentile



Diversified I yielded the best, least risk, results. This advantage arose from its lower 95th percentile ranking and its higher 5th percentile ranking. Thus, expected PVRRs fall within a narrower range. While Diversified I enjoys the least risk position, Diversified II and III closely follow its performance.

Producing a higher risk profile, the Renewable portfolio high 95th percentile overwhelms its correspondingly high 5th percentile. The resource configuration of Diversified IV brings the greatest degree of variation under this measure. A high 95th percentile combines with its low 5th percentile to produce the greatest range of potential outcomes.

Coefficient of Variation

The coefficient of variation is an alternative measure of risk. It equals the standard deviation of the 100 risk iterations divided by their mean. Standard deviation alone is a measure of the relative dispersion (and risk) of iterative outcomes. Dividing by the mean tends to reduce confusion caused when comparing distributions with different means.

While valuable for comparisons, this measure doesn't provide a complete picture of risk within the context of the IRP. Stated as a percentage, the measure doesn't convey the dollar variability associated with each portfolio. Defining such dollar variability is an important element of customer impact analysis, discussed later in this chapter.

Table 7.5 Coefficient of Variation

Portfolio	Coefficient of Variation
Diversified 1	15.962%
Diversified 2	16.553%
Diversified 3	16.387%
Diversified 4	18.194%
Renewable	16.784%

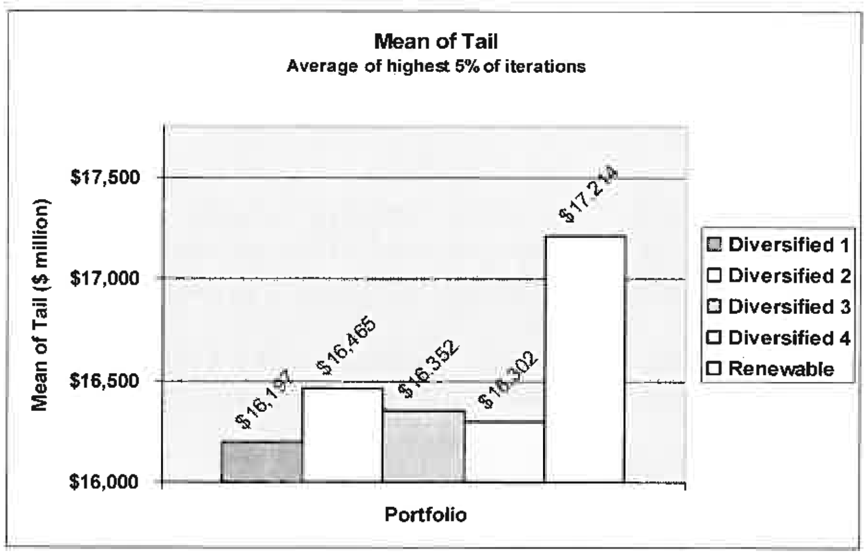
Consistent with other risk measures, the Diversified I portfolio demonstrates the least risk while the Diversified IV portfolio offers the greatest degree of variability. Also consistent with other measures, the coefficient of variation of the portfolios is tightly grouped.

Mean of Tail

The mean of tail is the simple average of the highest 5% of the simulated PVRR observations. Alternatively stated, it is the average of the five worst-case observations. This measure helps explore the tail risks of portfolios and represents the impact of the skewed distributions discussed in Chapter 3.

The metric is useful for comparative purposes, but should be considered with caution. By definition it averages just five values. Furthermore, as a simple-average it can be dramatically influenced by a single extreme observation.

Figure 7.11 Mean of Tail



The mean of tail associated with Diversified I further confirms the portfolio's lowest risk position. Intended to reflect the most extreme of potential outcomes (the worst 5 out of 100), this measure shows Diversified I is prone to a more moderate series of 'worst-case' events. This measure was the highest for the Renewable portfolio. It is clear that Renewable portfolio has greater tail risks than the other portfolios.

Like the 95th percentile, the mean of tail observations tended to occur when high natural gas prices intersect with high loads. However, Diversified IV, with the greatest proportion of natural gas fired resources, performs nearly as well as Diversified I. The reason can be found within the iterations comprising the highest five PVRR observations. While the highest five observations tended to occur at the general intersection of high loads and natural gas prices, two of the five iterations occurred when loads neared the 100th percentile while natural gas prices resided near the bottom of the upper quartile. From a total PVRR standpoint, these iterations were tail events. However, the natural gas exposure and the resulting PVRR of Diversified IV were reduced by the more moderate natural gas prices.

Risk Tradeoff

The information above provides valuable comparisons between key portfolio metrics. These comparisons are only the first step in evaluating portfolio risk performance. The next step requires evaluating the tradeoff between investment and risk. Evaluating portfolios in this manner provides useful insight. Superior portfolios should demonstrate a superior tradeoff.

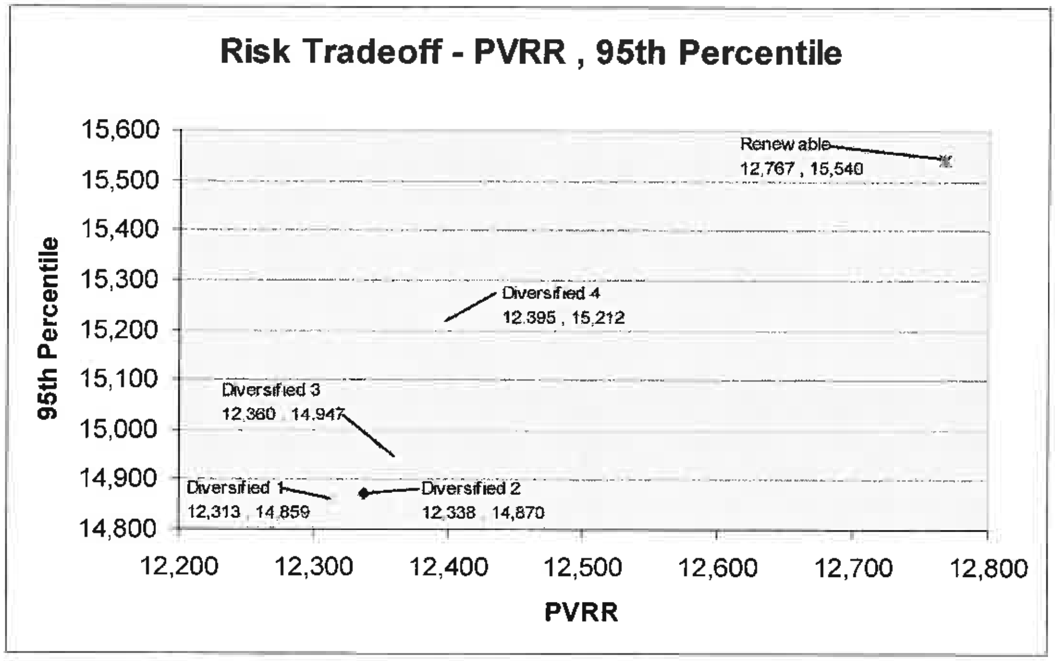
This section details the risk tradeoff associated with two measures. First, this section presents the PVRR relative to the 95th percentile. Second, this section presents the PVRR relative to the 95th – 5th percentile.

PVRR vs. 95th Percentile

Figure 7.12 demonstrates the tradeoff between the PVRR and risk. Interpreting the results of this graph is a matter of comparing the investment required by each portfolio (PVRR) against the overall risk the portfolio demonstrated in the model. For purposes of this figure, risk is defined as the 95th percentile.

Stakeholders are assumed to universally prefer lower risk portfolios at any specific investment level. Therefore, portfolios approaching the origin of Figure 7.12 generally dominate those more distant. Under this rule of thumb, Diversified I appears to be the dominant portfolio.

Figure 7.12 PVRR vs. 95th Percentile



Several points are illustrated by Figure 7.12.

First, the Diversified I and Renewable portfolios fall at opposite points. The Renewable portfolio has the largest PVRR of the top portfolios. Interestingly, this portfolio also has the greatest degree of risk. This figure demonstrates that the Renewable portfolio has the least efficient tradeoff between investment and risk.

Second, Diversified III and IV require greater PVRR commitments than Diversified I. Like Renewable, they also feature greater risk than Diversified I. Therefore, Diversified I dominates Diversified III and IV.

Third, Diversified I and II demonstrate a nearly identical risk profiles. However, the expected PVRR of Diversified II is somewhat higher. Given this less efficient tradeoff, it is concluded that Diversified I also dominates Diversified II.

"Dominant," as used herein, merely conveys that one portfolio, when compared to another, appears to contain a superior collection of resource choices. The word, however, is not intended to connotate the strength or magnitude of that superiority.

PVRR vs. 95th – 5th Percentile

The 95th percentile alone does not provide a complete picture of risk. The Figure 7.13 employs a different risk measure, 95th – 5th percentile, in order to evaluate the tradeoff between PVRR and risk. Interpretation of this figure is performed in the same manner as before. Results closer to the origin are generally preferred. As such, Diversified I, again, appears as the dominant portfolio.

Figure 7.13 PVRR vs. 95th – 5th Percentile

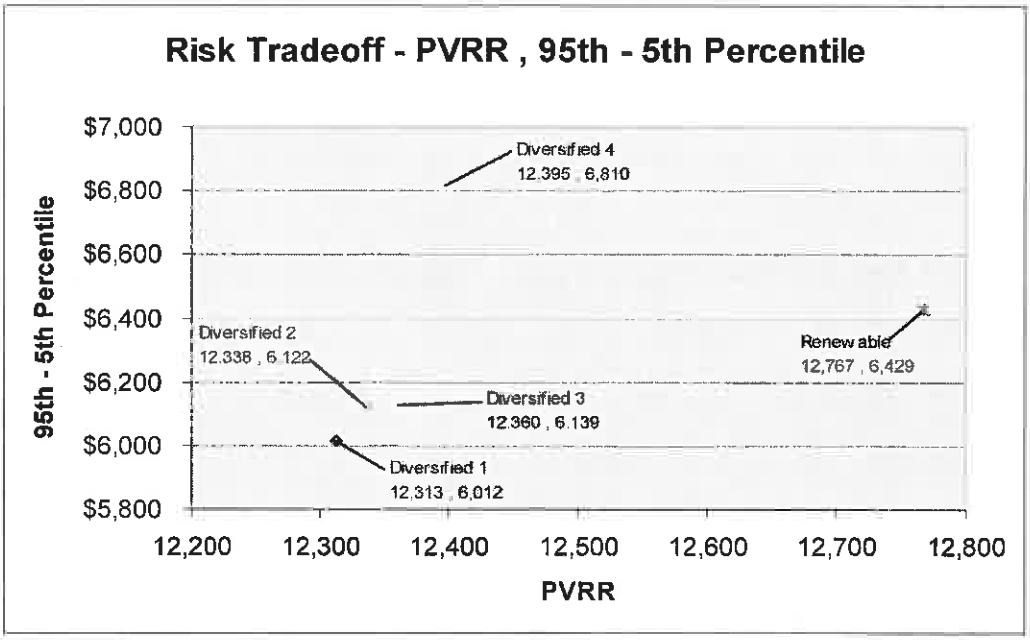


Figure 7.13 reinforces earlier observations.

- Diversified I and Renewable reside at opposite points of the graph with Renewable demonstrating the least efficient tradeoff between PVRR and risk.
- Diversified I has lower risk and a lower expected PVRR commitment than Diversified II, III and IV. Accordingly, Diversified I is viewed to dominate the other three.

Natural Gas Price Sensitivity

Observed in the analysis, high PVRRs tend to occur at the intersection of high natural gas prices and high loads. This section adds to that discussion by providing additional analysis of the impact of natural gas prices and portfolio costs. Here, natural gas price sensitivity was assessed by load normalizing portfolio performance.

To load normalize portfolio performance divide the revenue requirement (expressed in dollars) by the energy demanded (expressed in MWhs). The resulting costs are expressed on a $/MWh basis. The Customer Impacts section later in this chapter discusses this process further.

Movement in loads dramatically affects PVRR. The impact may mask the influence of other stochastic measures. Normalizing generally isolates the cost impact of other Stochastic risks from load.

While helping provide insight into the impact of other variables, drawbacks exist. For example, the remaining stochastic variables are not individually isolated. Therefore, within iterations the specific impact of unit outages, hydroelectric conditions as well as natural gas and power prices must be inferred.

Figures 7.14 – 7.17 provide the results of this analysis. The graphs portray the performance of Diversified I and IV. These portfolios, respectively, contain the lowest and highest exposure to natural gas. Therefore, illustrating them frames the comparisons of natural gas price exposure.

The x-axis plots the annual average natural gas prices simulated at Mid-Columbia. The y-axis plots load normalized portfolio costs, expressed in dollars per MWh. Figures 7.14 and 7.15 plot the costs observed when simulated loads were high. Conversely, Figures 7.16 and 7.17 plot costs when loads were low.

Figure 7.14 Div I High Loads and Natural gas

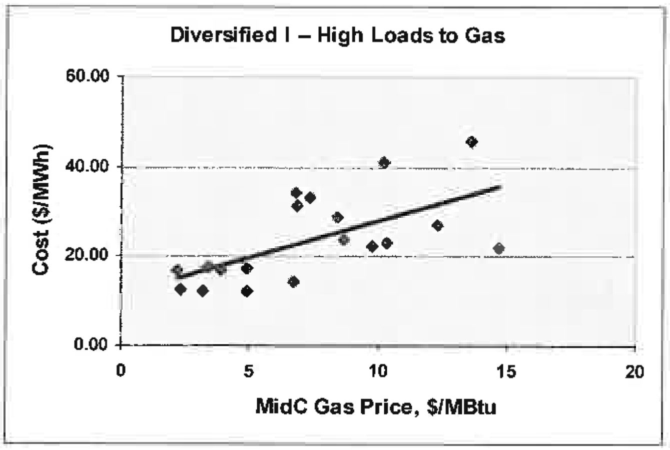


Figure 7.15 Div IV High Loads and Natural Gas

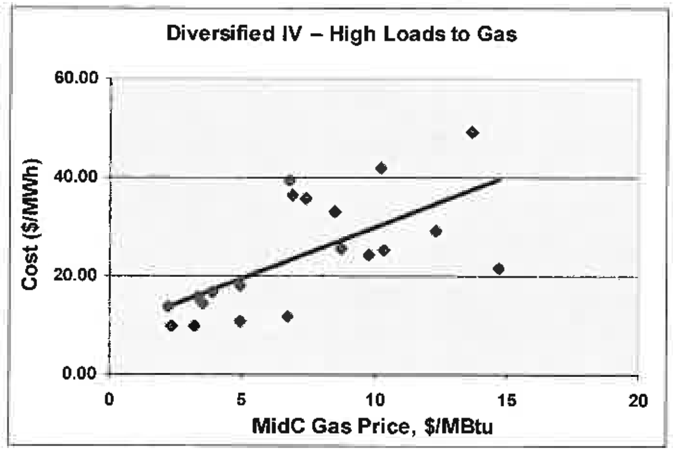


Figure 7.16 Div I Low Loads and Natural Gas

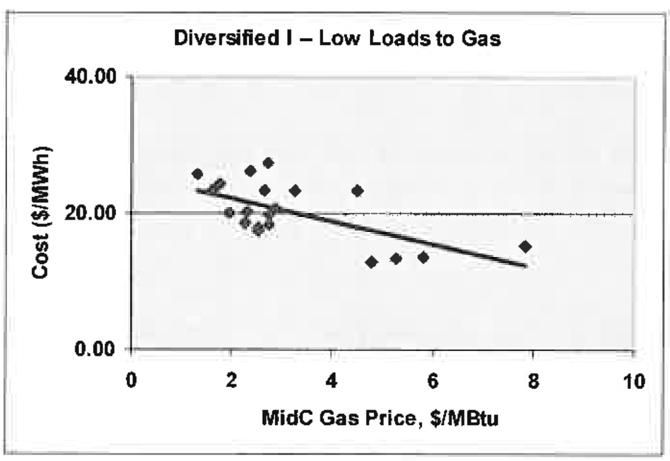
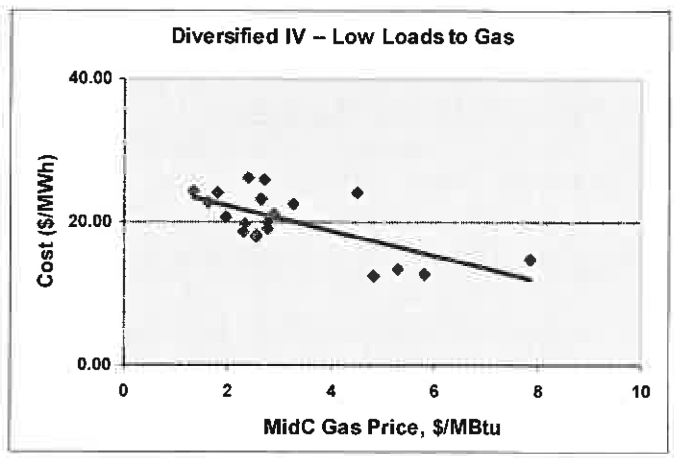


Figure 7.17 Div IV Low Loads and Natural Gas



The analysis shows the natural gas to cost relationship is not constant. Rather the sensitivity to natural gas price appears to depend on the system loads. The observation is intuitive and consistent with the earlier risk results. Natural gas and electricity prices are highly correlated. When loads are low, sales of surplus electricity generate more revenue when natural gas prices (and power prices) are high. The resulting revenues drive down costs. When loads are high, the reverse is true with fewer sales and more purchases producing greater costs.

The top panels represent iterations where loads are high. Here costs tend to increase with natural gas prices. In the bottom panels, higher natural gas prices drive costs down. For these iterations, high fuel prices (and with them, high electricity prices) coincide with low loads.

This general result applies to all IRP portfolios. Because power prices are highly correlated with natural gas prices (power prices can be viewed as a derivative of the natural gas prices), even a resource mix with no natural gas-fired generation would be short or long natural gas, contingent on what happens to system loads.

Generally speaking, portfolios with more natural gas generation should be more sensitive to natural gas price movements when short power, and less sensitive to natural gas price variations when power is surplus. However, because the share of natural gas fired generation in each resource mix tends to be low even in the more natural gas intensive IRP portfolios, this effect appears insignificant. Indeed, it can be seen from Figures 7.16 and 7.17 that the differences in cost sensitivity to natural gas price between the IRP portfolios with the least (Diversified I) and the most (Diversified IV) amount of natural gas fired generation, are very small.

A further conclusion may be inferred from this analysis. A high observation of any one risk parameter, may not be enough to cause a given year to result in high costs. Useful information, therefore, cannot be obtained by simply moving individual variables in isolation. Rather the convergence between events drives PVRR. For example high loads, high natural gas prices, high unit outages and low hydroelectric output converged to drive costs, as observed during the recent past. Hence, high natural gas prices sometimes reduce PVRR (when loads are low) and sometimes increase it (when loads are high).

East – West Risk

Some participants in the public process requested a risk analysis divided between east and west portfolio sub-categories. The current IRP model performs the risk analysis on an integrated basis. It does not yet allow for regional cost segmentation. This is an enhancement targeted for the next IRP.

CUSTOMER IMPACT

This section characterizes the costs on a per MWh basis. Describing cost per unit of energy better represents the impact on customer rates. It also helps reflect the rate changes, which might be required moving from one year to another. This analysis, while providing an indication of rate direction, does not represent rates fully allocated by state and customer class. Table 7.6 provides additional details and reflects the following:

- PVRR using both a real levelized and a nominal revenue requirement calculation for resource and transmission capital expenditures
- PVRR discounted at both PacifiCorp's after-tax weighted average cost of capital (7.5%) and the general escalation rate (2.5%)
- A 20-year average $/MWh utilizing the revenue requirements as stated in constant dollars (discounted at the escalation rate)

Calculation Method

Discount Rate

Each portfolio PVRR is calculated using real levelized revenue requirements for resource and transmission capital. Additionally, the nominal revenue requirements are calculated and presented at the request of those wishing to see a 20-year PVRR calculated using traditional ratemaking methodology. Portfolios are also shown discounted at PacifiCorp's weighted average cost of capital (WACC) and at the general escalation rate. Additionally, the constant $/MWh results were calculated by taking the PVRR, calculated using a 2.5% discount rate, and dividing it by the 20-year sum of MWh.

Relative Rank

Table 7.6 also shows, within each measurement methodology, what percent each portfolio's PVRR is above the least cost portfolio. The results indicate that the relative ranking among the portfolios do not materially change when applying alternative measurement methodologies.

Table 7.6 Real Levelized versus Nominal PV versus Constant

	Present Value Results Discounted at WACC		Constant Dollar Results Discounted at Escalation Rate		Constant Dollar Results 20-Yr Average $/MWh	
Discount Rate	**w/ real levelized 4/1/2003 PVRR 7.5%**	**w/ nominal (1) 4/1/2003 PVRR 7.5%**	**w/ real levelized 4/1/2003 PVRR 2.5%**	**w/ nominal (1) 4/1/2003 PVRR 2.5%**	**w/ real levelized 4/1/2003 PVRR 2.5%**	**w/ nominal (1) 4/1/2003 PVRR 2.5%**
Diversified I	12,313	12,895	21,684	22,369	$15.26	$15.74
Diversified II	12,338	12,940	21,716	22,474	$15.28	$15.82
Diversified III	12,360	12,926	21,757	22,457	$15.31	$15.80
Diversified IV	12,395	12,871	21,855	22,405	$15.38	$15.77
Alternative Technology II	12,559	12,974	22,180	22,583	$15.74	$16.03
Coal/Gas III	12,651	13,141	22,300	22,955	$15.69	$16.15
PacifiCorp Build – I	12,679	13,189	22,332	23,060	$15.71	$16.22
Gas/Coal I	12,706	13,180	22,386	23,056	$15.75	$16.22
Gas/Coal II	12,715	13,188	22,396	23,064	$15.76	$16.23
Gas/Coal III	12,743	13,216	22,435	23,091	$15.78	$16.24
PacifiCorp Build II	12,748	13,258	22,477	23,208	$15.81	$16.33
Peakers	12,759	13,215	22,489	23,134	$15.82	$16.27
Renewable	12,767	13,235	22,569	23,062	$15.88	$16.23
Alternative Technology I	12,770	13,081	22,475	22,620	$15.94	$16.05
All Gas II	12,865	13,251	22,706	23,219	$15.97	$16.33
Wyoming Coal	12,868	13,360	22,694	23,394	$15.96	$16.46
All Gas I	12,889	13,264	22,739	23,225	$16.00	$16.34
Coal/Gas II	12,908	13,317	22,771	23,264	$16.02	$16.36
Coal/Gas I	12,910	13,368	22,759	23,336	$16.01	$16.41
Transmission - 1000MW DC	13,018	13,737	22,969	24,012	$16.15	$16.89
Transmission - 2000MW DC	13,218	14,022	23,357	24,546	$16.43	$17.26
Transmission - Asset Build Market	13,221	13,662	23,420	24,034	$16.48	$16.91
Coal/Gas III - 10%	12,358	12,819	21,808	22,451	$15.35	$15.80
Gas/Coal I - 10%	12,376	12,807	21,814	22,466	$15.34	$15.80
PacifiCorp Build II - 10%	12,531	13,019	22,129	22,875	$15.56	$16.09
All Gas II - 10%	12,576	12,934	22,220	22,723	$15.63	$15.99

Percent above Least Cost Portfolio Discount Rate	**w/ real levelized 4/1/2003 PVRR 7.5%**	**w/ nominal (1) 4/1/2003 PVRR 7.5%**	**w/ real levelized 4/1/2003 PVRR 2.5%**	**w/ nominal (1) 4/1/2003 PVRR 2.5%**	**w/ real levelized 4/1/2003 PVRR 2.5%**	**w/ nominal (1) 4/1/2003 PVRR 2.5%**
Diversified I	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%
Diversified II	0.2%	1.0%	0.1%	0.5%	0.1%	0.5%
Diversified III	0.4%	0.9%	0.3%	0.4%	0.3%	0.4%
Diversified IV	0.7%	0.5%	0.8%	0.2%	0.8%	0.1%
Alternative Technology II	2.0%	1.3%	2.3%	1.0%	3.1%	1.8%
Coal/Gas III	2.7%	2.6%	2.8%	2.6%	2.8%	2.6%
PacifiCorp Build – I	3.0%	3.0%	3.0%	3.1%	2.9%	3.0%
Gas/Coal I	3.2%	2.9%	3.2%	3.1%	3.2%	3.0%
Gas/Coal II	3.3%	3.0%	3.3%	3.1%	3.2%	3.1%
Gas/Coal III	3.5%	3.2%	3.5%	3.2%	3.4%	3.2%
PacifiCorp Build II	3.5%	3.5%	3.7%	3.7%	3.6%	3.7%
Peakers	3.6%	3.2%	3.7%	3.4%	3.6%	3.4%
Renewable	3.7%	3.3%	4.1%	3.1%	4.1%	3.1%
Alternative Technology I	3.7%	2.1%	3.6%	1.1%	4.5%	1.9%
All Gas II	4.5%	3.5%	4.7%	3.8%	4.7%	3.7%
Wyoming Coal	4.5%	4.3%	4.7%	4.6%	4.6%	4.5%
All Gas I	4.7%	3.6%	4.9%	3.8%	4.8%	3.8%
Coal/Gas II	4.8%	4.0%	5.0%	4.0%	4.9%	3.9%
Coal/Gas I	4.8%	4.4%	5.0%	4.3%	4.9%	4.3%
Transmission - 1000MW DC	5.7%	7.3%	5.9%	7.3%	5.8%	7.3%
Transmission - 2000MW DC	7.3%	9.5%	7.7%	9.7%	7.6%	9.6%
Transmission - Asset Build Market	7.4%	6.7%	8.0%	7.4%	8.0%	7.4%
Coal/Gas III - 10%	0.4%	0.1%	0.6%	0.4%	0.5%	0.3%
Gas/Coal I - 10%	0.5%	0.0%	0.6%	0.4%	0.5%	0.4%
PacifiCorp Build II - 10%	1.8%	1.7%	2.1%	2.3%	2.0%	2.2%
All Gas II - 10%	2.1%	1.0%	2.5%	1.6%	2.4%	1.5%

The comparisons in Table 7.6 of present value vs. constant dollar results and capital costs are calculated using real levelized vs. nominal revenue requirements. Results are based on model runs prepared for the final report. Note: (PVRR Results Are In Millions Of Dollars).

Capital Life – End Effects
It should be noted that the results presented using the nominal revenue requirement calculation do not include an adjustment for capital life end-effects. The analysis period is 20 years, and most of the assets' lives extend well beyond the end of the analysis. This results in the higher-cost revenue requirements incurred in the early years of a capital addition's economic life to be included in the PVRR while the lower cost revenue requirements of later years are excluded.

Without some type of end-effects adjustment, the capital-intensive portfolio's PVRR will tend to show a relatively higher nominal revenue requirement. While utilizing nominal revenue requirements is more reflective of future ratemaking impacts during the 20-year analysis period, it does not, by itself, provide proper comparative economics needed to address the relative costs of long-lived assets.

Revenue Requirement Impacts

IRP Footprint
The IRP customer impacts calculation includes only the $/MWh rate impacts associated with the IRP "footprint" as compared to total PacifiCorp historical $/MWh (CY 2001 actual retail $/MWh was used for comparison).

The IRP footprint includes electricity supply system costs for fuel, variable plant O&M, emission allowance impact, start-up costs, market contracts, spot market purchases and sales, production tax credits, green tag benefits, renewable integration costs, and DSM costs. It also includes all of the revenue requirement costs associated with adding incremental investment in new resources and new transmission. However, the IRP footprint does not include certain costs that are deemed common to all IRP portfolios. The excluded costs are existing generation assets' capital revenue requirement, existing generation assets fixed O&M, future air emissions costs, hydro relicensing costs, and other non-electricity supply costs such as distribution, transmission and general plant capital and operating costs.

Impact Calculation
The IRP customer impact calculation is as follows: portfolio $/MWh is calculated annually by dividing the total revenue requirement of the IRP footprint by the IRP load projections. Each year is compared with the previous year's $/MWh to derive the $/MWh increase. This $/MWh increase is then divided by calendar year 2001's actual retail rate of $48.97/MWh. (The CY 2001 $/MWh was chosen as a benchmark anchor to which all other years are compared. Figure 7.6 provides an example.) This provides an "indicative" percentage increase attributed to the IRP portfolio for that year.

Effect on Rates
Because the IRP excludes costs common to all portfolios, the customer impacts calculation is only relevant when comparing one IRP portfolio against another. While the impact calculation provides yearly directional implications of rate changes associated with the IRP, it cannot provide a projection of total PacifiCorp revenue requirement impacts. It is only a portion of the total PacifiCorp revenue requirement. Likewise, the IRP impacts are a consolidated PacifiCorp look assuming immediate ratemaking treatment and make no distinction between current or proposed multi-jurisdictional allocation methodologies.

Table 7.7 IRP Annual Increase Calculation Example

Example Calculation of IRP Annual Increase as a Percent of CY 2001 Retail Rates

Using the Diversified Portfolio I

row		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1	IRP $/MWh Revenue Requirement	$ 8.78	$ 9.30	$ 11.03	$ 12.18	$ 13.91	$ 15.78	$ 16.28	$ 17.43	$ 19.93	$ 22.15	$ 22.41
2	Year on Year Increase $/MWh		$ 0.51	$ 1.73	$ 1.15	$ 1.73	$ 1.87	$ 0.50	$ 1.14	$ 2.50	$ 2.23	$ 0.26
3	CY 2001 Actual Average Retail Rate		$ 48.97	$ 48.97	$ 48.97	$ 48.97	$ 48.97	$ 48.97	$ 48.97	$ 48.97	$ 48.97	$ 48.97
4	Annual Increase over CY 2001 Retail Rates		1.1%	3.5%	2.3%	3.5%	3.8%	1.0%	2.3%	5.1%	4.5%	0.5%
5	Cumulative Increase over CY 2001 Retail Rates		1.1%	4.6%	6.9%	10.5%	14.3%	15.3%	17.6%	22.8%	27.3%	27.8%

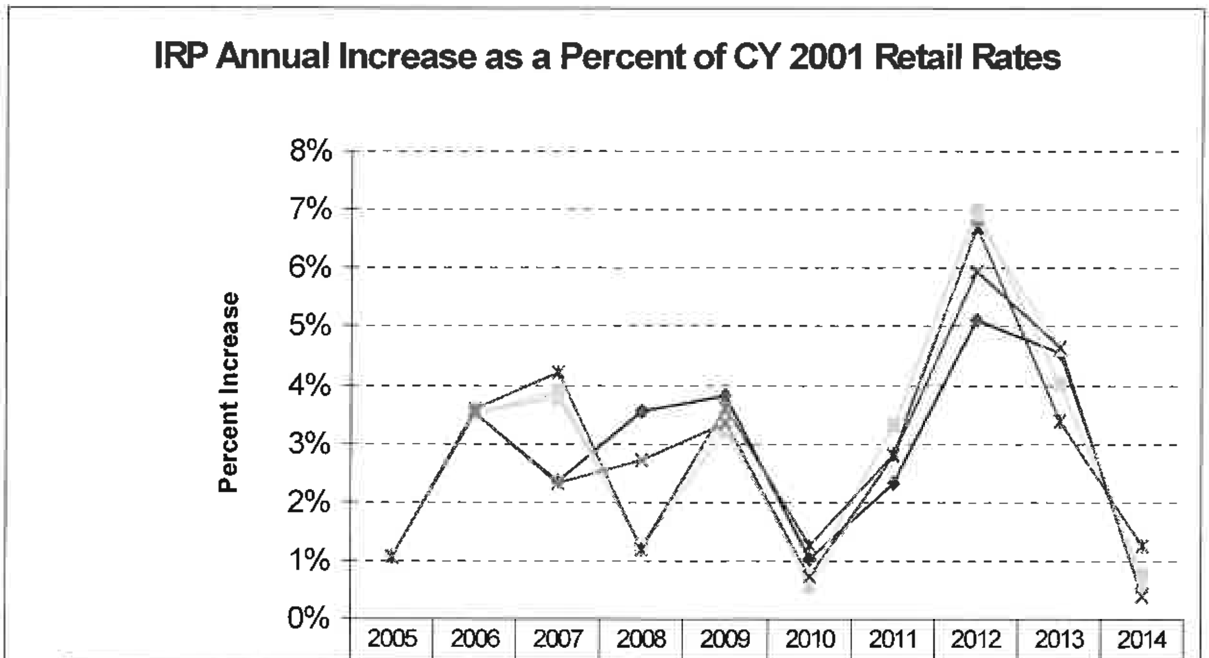
Explanation of Calculations:

These calculations assume immediate rate-making treatment, i.e., all operating costs are recovered through rates as incurred and all new capital is included in rate base when placed in service.

The IRP revenue requirement includes only the impacts suggested by IRP, including system costs for fuel, variable O&M, emission allowance impact, start-up cost, market contracts, spot market purchases and sales, DSM cost, and all revenue requirement costs associated with adding incremental Investment in new resources and new transmission.
The IRP revenue requirement excludes existing distribution, transmission and general plant capital and operating costs.
It also excludes the fixed costs of existing generation assets which are the same in each portfolio.

row 1	Annual revenue requirement for this IRP Portfolio divided by corresponding annual MWh Load.
row 2	Current year $/MWh in row 1 minus prior year $/MWh in row 1.
row 3	Calendar year 2001 retail revenue divided by retail MWhs sold. Used as a "benchmark" to which each annual IRP revenue requirement increase is compared against.
row 4	Row 2 divided by row 3
row 5	Cumulative sum of row 5. Another method for calculating this is (ending year $/MWh, row 1, minus 2004 $/MWh, row 1) divided by $48.97. For example, the 2014 cumulative increase of 30.2% is ($23.66/MWh minus $8.88/MWh) divided by $48.97/MWh.

Figure 7.18 IRP Annual Increase as a Percent of CY 2001 Retail Rates



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Diversified Portfolio I	1.1%	3.5%	2.3%	3.5%	3.8%	1.0%	2.3%	5.1%	4.5%	0.5%
Diversified Portfolio II	1.1%	3.5%	3.9%	1.2%	3.2%	0.7%	3.3%	7.0%	4.0%	0.8%
Diversified Portfolio III	1.1%	3.5%	3.8%	1.3%	3.5%	0.6%	2.9%	6.8%	4.6%	0.6%
Diversified Portfolio IV	1.1%	3.5%	2.3%	2.7%	3.4%	0.7%	2.8%	5.9%	4.7%	0.4%
Renewable Portfolio	1.1%	3.6%	4.2%	1.2%	3.6%	1.3%	2.8%	6.7%	3.4%	1.2%

Customer Impacts – General Conclusions

Consistent with the PVRR findings, Diversified portfolio I requires the smallest rate increases, using this methodology. Also, as shown above in Figure 7.18, the impacts associated with the IRP in the early years are similar among all portfolios.

STRESS TESTING

Described in Chapter 3, certain inputs do not naturally lend themselves to randomized variation within the models. Understanding the nature of these variables and their impact on portfolio performance therefore requires deliberate manipulation of their values. Model assumptions selected for this type of stress testing or scenario analysis include:

1) Modifying the assumed value of CO_2 allowance costs
2) Removing wind capacity
3) Modifying wind resource cost assumptions
4) Removing wind capacity and the carbon allowance costs
5) Attributing 15% wind capacity to planning margin

6) Begin installation of wind one year earlier
7) Replacing Hunter 4 with IGCC in 2012
8) Replace peaking units with CCCTs
9) Varying timing and order of three large East units
10) Altering hydro resources to account for re-licensing impacts
11) Changing West loads to model SB 1149 impacts
12) Modifying the amount and cost of DSM within portfolios
13) Changing the planning margin assumption

Each stress test was designed to provide insight into Scenario and Paradigm risks. The results of the testing are important. They demonstrate that the path ultimately taken by each risk can significantly alter the risk and cost profile of different portfolios. Collectively, they demonstrate the need for planning flexibility. Such flexibility in the development of portfolios is the most practical means of addressing each risk.

Because the scope and number of stress tests is broad, Table 7.8 summarizes them. Details of each analysis follow.

Table 7.8 Summary of IRP Stress Test

Stress Name	Description	Portfolios Tested*	Conclusions
1) Modifying CO_2 Allowance Costs	Vary CO_2 cost. Compare assumptions of \$0/ton, \$2/ton, \$25/ton, \$40 to base of \$8/ton	DP1, DP2, DP3, DP4, RP	• PVRR escalates with increase in CO_2 allowance cost • Greater clarity needed prior to fuel selection • Renewable and natural gas resources hedge against CO_2 allowance costs
2) Removing wind capacity	Remove wind capacity from the top three portfolios	DP1, DP2, DP3	• Profiled wind additions reduce costs • Findings support seeking a greater understanding of renewables as part of the resource stack
3) Modify wind resource cost assumptions	Vary assumptions for Production Tax Credit (PTC), green tags, transmission, and integration	DP1	• PTC provides greatest incentive of Renewable development • Transmission costs have potential to outweigh financial benefits from new wind • Green tag and integration cost assumptions are important but not the most significant factors in the decision making process • Continuous refinement of wind cost assumptions is necessary
4) Remove CO_2 allowance cost *and* wind capacity	Compare assumption of \$0/ton CO_2 cost and no wind capacity in portfolios with assumptions of \$0/ton CO_2 cost with wind capacity	DP1, DP2, DP3	• Very slight increase in PVRR • Additional renewables hedge against CO_2 allowance costs but offer imperceptible financial benefit without the allowance cost.
5) Attribute wind capacity to planning margin	Count 15% of total wind capacity towards planning margin.	DP1, DP2, DP3	• PVRR declines by \$100m for all portfolios • Making up for resource reductions, existing system generation and market purchases increase • Further industry analysis required before % contribution can be determined for planning.
6) Install wind earlier	Move installation of wind one year forward to FY 2005	DP1, DP2, DP3	• Less than 0.2% increase to PVRR. Tradeoff occurs between reduction in operations costs vs. earlier costs of acquiring resource • All responses to RFPs will be evaluated on an individual basis. IRP does not set a rigid timeline for wind resources (see Action Plan).

7) Replace Hunter 4 with IGCC	Replace Hunter 4 in 2012 with a 1x1 CCCT at Mona and an IGCC unit	DP3	• 1.4% increase to PVRR with reduced emissions • Technology advance may improve availability and lower costs
8) Replace peaking units with CCCTs	Replace peaking units with CCCTs featuring an earlier installation timeline	DP1	• <1% increase to PVRR • Increase to market sales • Reduction in capacity factors of new CCCTs to 12-37%. • >20% capacity planning margin through 2011
9) Vary the timing and order of large East units	Test the impact of changing the installation timeline of the three large East resources	DP1 and DP3	• First installation in 2008 superior to 2007 • DP 1 is least cost, however each variation's PVRR is within less than 1%.
10) Hydro licensing impacts	Removed 214 MW of owned Hydro capacity in FY 2006. Replace with 1x1 CCCT.	DP1, DP2, DP3	• Large increase, \$608 million to PVRR • Hydro is a valuable system resource • Detailed plant specific analysis will be completed as relicensing occurs
11) SB1149 impacts	Removed 400 MW load in OR and remove West resources accordingly.	DP1, DP2, DP3	• Large decrease to PVRR, \$1.78 billion • Significant impact to West planning • Additional transmission loss studies required • Planned large build in 2007 could be delayed or decreased due to loss of load
12) DSM Decrements	Model several program load shapes of various load factors decremented from load files to calculated a decrement value for the program	D1	• Provides preliminary guidance in future DSM program design and valuation • As load factors increase, breakeven program costs decrease • Distribution costs and program feasibility must be evaluated outside this study
13) Change planning margin assumption	Redesign portfolios from a 15% to a 10% planning margin	Gas/Coal I, Coal/Gas III, PacifiCorp Build II and All-Gas II	• The effect of the lower margin (in MW added) by 2013 is between 500 and 550 MW. • A 10% planning margin requires slightly higher contingency market participation (7,000MWh/yr vs. 1,000 MWh/hr) • The decision to build to a 10% or 15% planning margin will be subject to regional policy issues

*DP = abbreviation for Diversified Portfolio, RP = Renewable Portfolio

1) CO_2 Stresses

The results of the carbon dioxide (CO_2) emissions allowance cost stresses applied to the Diversified I - IV and Renewable portfolios are summarized in Appendix E, Tables E.4 to E.7. CO_2 emissions are not currently regulated, but may be in the future. As a base case assumption,

CO_2 allowance costs were modeled at $8/ton in all portfolios beginning in FY 2009 for each ton emitted above the calendar year 2000 total. Likewise, emissions under the cap received an $8/ton credit. This stress tests the impact to PVRR due to variation of the amount, timing, and cap level of this assumption.

As discussed in Chapter 3, the CO_2 allowance cost is considered to be a Scenario Risk. Accordingly, upper and lower limits are tested manually to determine the impact to each portfolio. The following is the profile of modeled CO_2:

- Base Case $8/ton cap allowance used is CY 2000 actual, beginning in FY 2009
- $0/ton, without a cap
- $2/ton, cap used is CY 2000 actual, beginning in FY 2013
- $25/ton, cap used is CY 1990 actual, beginning in FY 2008
- $40/ton, cap used is CY 1990 actual, beginning in FY 2008

Observations

- PVRR escalates with the increase of CO2 allowance cost rate
- Existing thermal unit operation decreases with the increase of CO2 allowance cost rate, prompting an increase in market purchases and a decrease in market sales, for both East and West. Given PacifiCorp's higher than market proportion of coal fired generation, this finding is intuitive.
- East to West transfers decrease and West to East transfers increase as CO2 allowance cost increases due to reduced operation of new and existing coal and natural gas units and greater reliance on spot markets.
- Total 2009-2023 CO2 emissions at the $40/ton allowance cost rate are 92% of total emissions in the $0/ton case for each portfolio. These reductions are achieved at a 20-27% increase to overall PVRR (See Figure 7.19).
- CO2 stresses impact the relative ranking of portfolios, measured by PVRR.

Using the PVRR as a measure, Diversified I placed first at $0, $2, and $8/ton CO_2 allowance cost. Somewhere between $8/ton and $25/ton the merit switches to Diversified IV with Diversified II placing second. The all gas portfolio, Diversified IV, stays in first place thereafter as the CO_2 allowance cost increases.

Benefits are not limited explicitly to CO_2 related costs. Other pollutants follow course with the CO_2 trend, decreasing as the incremental allowance cost increases are applied to CO_2

Figures 7.19 and 7.20 below graphically illustrates the key observation of this analysis:

- The first three Diversified portfolios remain very close in PVRR for each case.
- Diversified IV, the all gas portfolio, remains in fourth position at the low end of the allowance cost but rises to first position at the higher allowance cost stresses.
- The timing of the coal plant installation (2008 vs. 2012) impacts the results of the PVRR ranking throughout the stress study.
- With a low CO2 allowance cost penalty and low cap, the portfolio with early coal, Diversified I, ranks first. The portfolio replacing west contracts with built resources,

Diversified II, ranks second followed by Diversified III, which features the late installation of coal and the retention of West contracts.

- As the cap lowers and the allowance cost rate increases, the order of least rank is reversed.

Figure 7.19 PVRR vs. Carbon Allowance Cost Scenarios

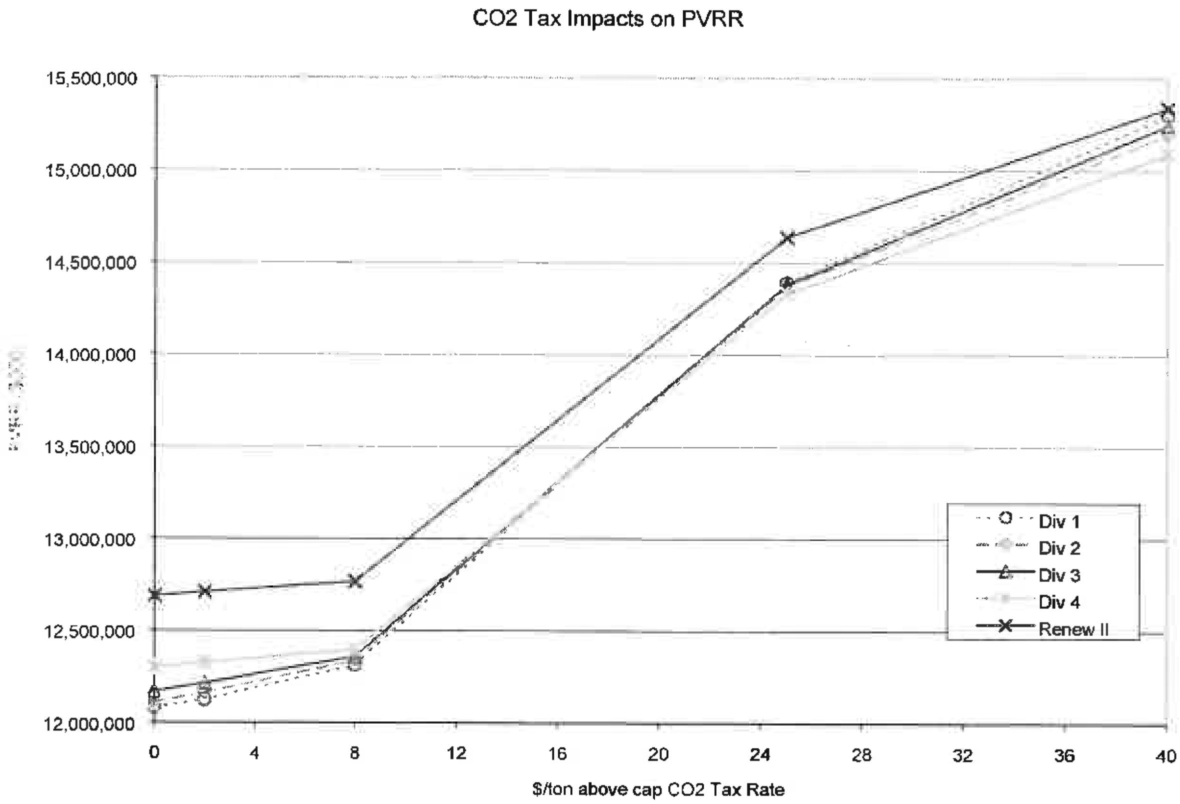
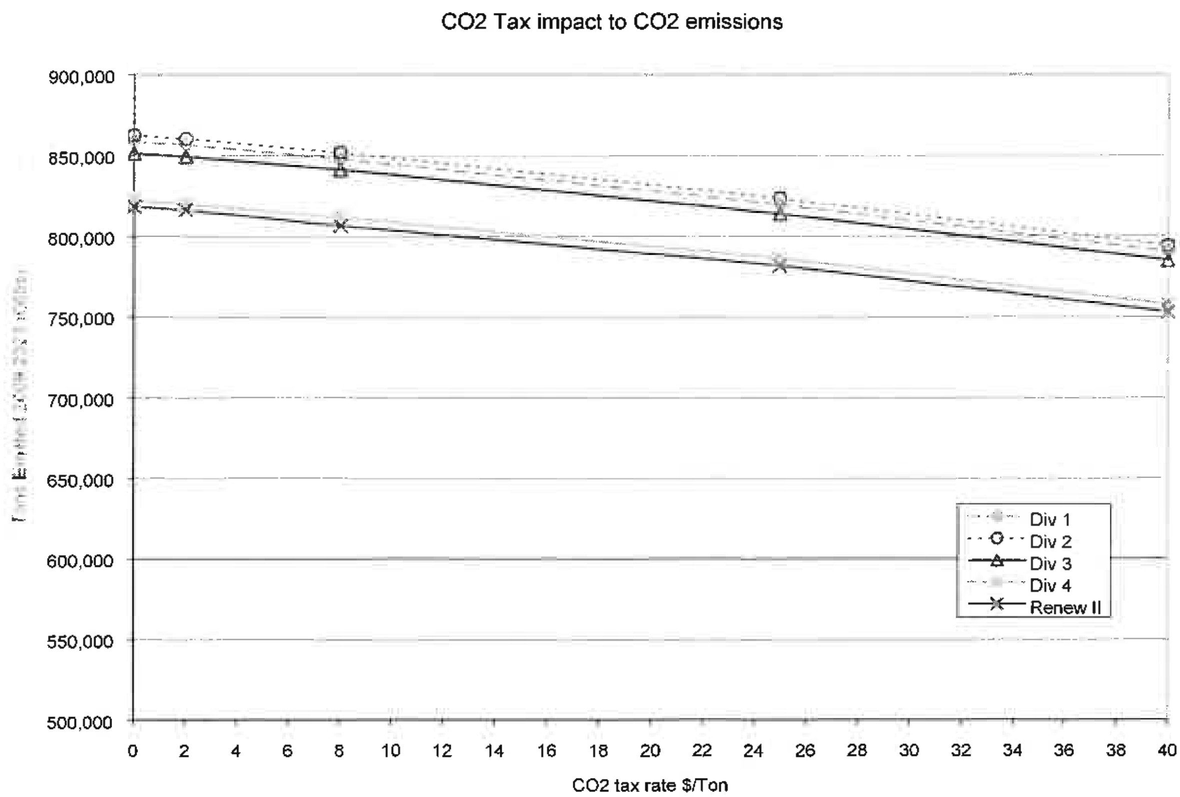


Figure 7.20 CO_2 Emissions vs. Carbon Allowance Cost Scenarios



CO_2 Stresses - General Conclusions

- Greater clarity on carbon allowance cost issues would be helpful prior to selecting generation plant fuel type
- Renewables should be further analyzed for their potential use as a hedge against environmental pollutants. The addition of wind resources greatly reduces the range of PVRR outcomes of the CO2 stress study.

2) No Additional Wind Capacity

The goal of this stress is to test the value in adding variable wind generation to the system portfolio. Diversified Portfolios I, II and III each include a gradually ramping, variable wind resource contract. Under this stress test, the wind contract is removed. Model outputs were then compared to the base case results of the top portfolios.

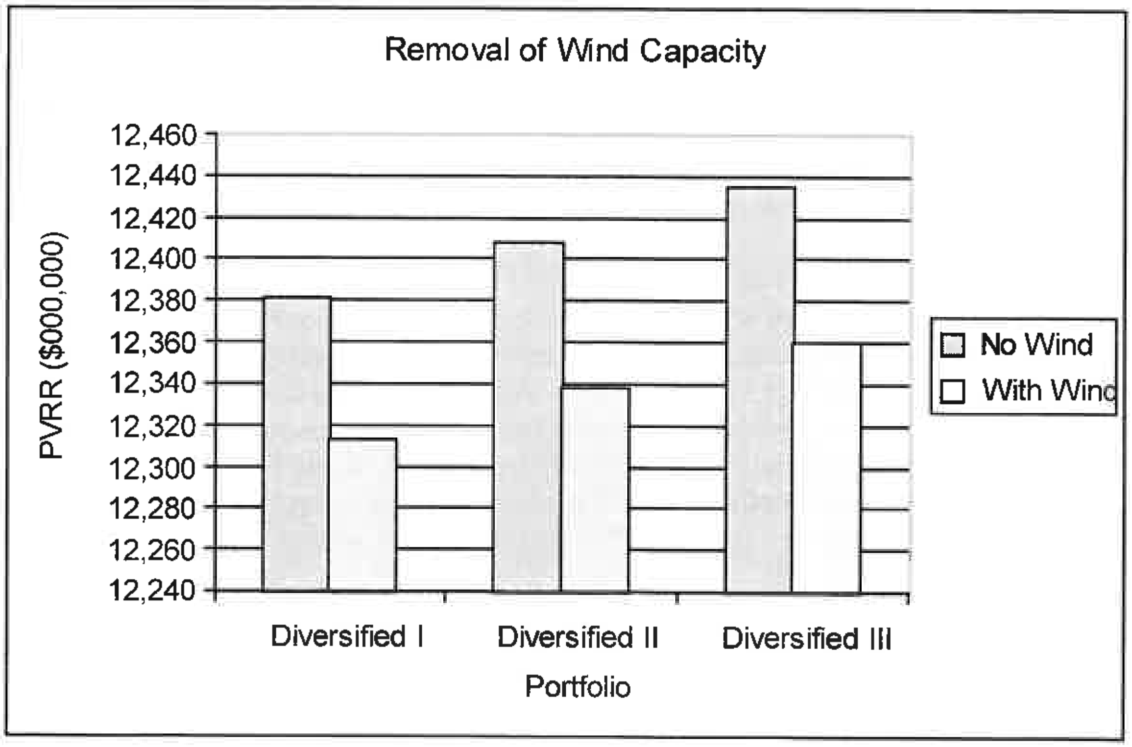
The wind resource was modeled as if it were a contract with a third party but attached to a wind plant with output varying by hour. The output is based upon actual historic generation data from plants located in each control area with representative hourly distribution shapes for the region. The pricing of the contract includes the capital cost of plant installation and transmission plus O&M and system integration. Some of these charges are offset by calculations for the Production Tax Credit and Green Tags based on the same assumptions as described previously in Chapter 6.

By removing the variable wind resource, the following impacts to the top portfolios are observed:

- Portfolio PVRR rises $68 - 75 million due to increase in net variable electricity cost
- The variable contract cost line-item declines $1.5 billion due to elimination of the long-term wind contract. While substantial, this cost decline was insufficient to overcome the increases in other variable costs.
- Emissions expenses rise $78-85 million with a 17 million ton increase in CO2 output from 2009-2023
- East market purchases increase slightly; West market purchases increase 10%
- In the East, existing coal and peaker units run at slightly higher capacity factors. IRP CCCT East capacity factor rises by 15% by 2014
- West existing resources also ran more often; CCCT capacity factor rises 18%. IRP CCCTs and peakers also ran more, increasing to 85% and 13% from an average of 78% and 10%

Figure 7.21 illustrates the PVRR differences between portfolios with and without the wind contract.

Figure 7.21 PVRR With and Without Wind



No Additional Wind Capacity - General Conclusions

- Adding wind capacity to the portfolios increases variable contract costs but reduces the overall PVRR.
- Wind resources reduce the capacity factors of existing and new units.

- With the above improvements come cost uncertainties, listed and analyzed in the next section.

This stress shows the wind as having an overall positive impact to the system costs and reduction to emissions and supports the continued pursuit of greater understanding of integrating renewables as part of the future resource mix.

3) Analysis of Wind Resource Variable Cost Impacts

Modeling shows wind resources reduce portfolio costs and risks. The purpose of this stress section is to identify the impact associated with the unique renewable energy cost assumptions. Many of these assumptions are uncertain and will impact the cost of developing and contracting for wind resources. Therefore, understanding the results in light of the value imputed by key cost assumptions is important. If these assumptions are stressed up or down, the modeling results may vary and change the pricing of the resource. Specifically, key variables are varied to observe the impact on the Diversified I portfolio.

The key variables in the Wind Resources of the Hybrid Portfolios include:

- Production tax credit (PTC)
- Green tag value
- Transmission
- System integration charges
- Carbon allowance costs
- Application of built wind capacity to planning margin

Each of these variables will be defined and quantified as they relate to the Diversified I portfolio.

Production Tax Credit

This tax incentive applies to new wind and geothermal plants with the intent of bringing their costs in line with other thermal resources. In the model, the tax credit applies to wind projects for the first 10 years of operation at $18/MWh. The credit also applies to new geothermal plants but only for the first 5 years of operation. Annual net operating expenses are directly credited at $18/MWh for each MWh produced by wind and geothermal plants for each year the incentive applies. This is an effective simplification for applying the cost. In reality, the benefits of the tax credit do not apply to the bottom line in such a straightforward manner.

The future of this tax credit is unknown. Although it has been extended through 2003, PacifiCorp assumes it will be continually extended. The PTC is assumed in effect for the life of the study, 2023. For the base case wind resources, the production tax credit reduces the 20-year PVRR by $353 million.

Green Tags

Green tags represent the environmental attributes of renewable energy. Such attributes can be traded between parties and therefore have a dollar value. With such value green tags help lower the installation and production costs of renewable power.

Green tags are the result of policy incentives to encourage renewable energy production. Incentives like the Federal Renewable portfolio Standard or similar state requirements are particularly important. At present, there is no federal RPS. Furthermore, with the exception of California, PacifiCorp's service territory does not fall within a state featuring an RPS. Independent of legislative requirements, utilities in the future could set proprietary renewable targets independent of a RPS.

Regardless of the outcome of the RPS or similar legislation, green tags are expected to be of value.

- **No RPS**: If a Renewable portfolio Standard does not pass, green-specific energy would not be required for PacifiCorp's proprietary consumption. Thus, all tags would be available for trading.
- **RPS Implemented**: If RPS is implemented, PacifiCorp's renewable generation allows it to avoid the market costs of procuring tags. Tags for generation above the Standard would be marketable.

While retaining some value independent of a legislative mandate, the amount of that value is uncertain.

In the model, new wind and geothermal plants are assumed to have a green tag value of $5/MWh for the first five years of production. This rate does not change through time, effectively reducing their value by inflation each year. In the hybrid portfolios, the green tags reduce the overall PVRR by $58 million. Table 7.9 shows the impacts to the 20-year PVRR and relative portfolio ranking when the tag value is increased to $9/MWh as well as if there was no material value for tags in the future ($0/MWh).

The key finding of this study is that changing green tag assumptions, alone, is not enough to impact the portfolio rankings. With no value for the green tags, the PVRR for this portfolio increases less than 1%. Diversified I retains its least cost rank compared to the same portfolio without the wind resources. Higher tag values increase the portfolio's advantage. Therefore, the future value of green tags alone does not appear to impact the overall decision to add wind resources to the portfolios.

Transmission

One major uncertainty associated with planning for new wind sites is the location of those plants and the additional transmission requirements to get generation into PacifiCorp's system. In the model, there are four separate locations for wind plants:

- Central Oregon,
- South central Washington,
- Wyoming, and
- Utah

Estimated transmission costs range from \$2/MWh to over \$4/MWh. As demand for wind sites grows, those most convenient to transmission may be developed first, leaving those sites requiring transmission upgrade investments with higher \$/MWh expenses.

In the base case for the Diversified I Portfolio, transmission ranges from \$2-4/MWh. For an estimated low case, transmission costs were assumed to be half that cost and at the high end, transmission was stressed to three times the base value. Table 7.9 and Figure 7.22 show that only by assuming transmission costs are three times the base assumed value will the overall cost of adding wind to the portfolio outweigh any financial benefits.

System Integration Costs

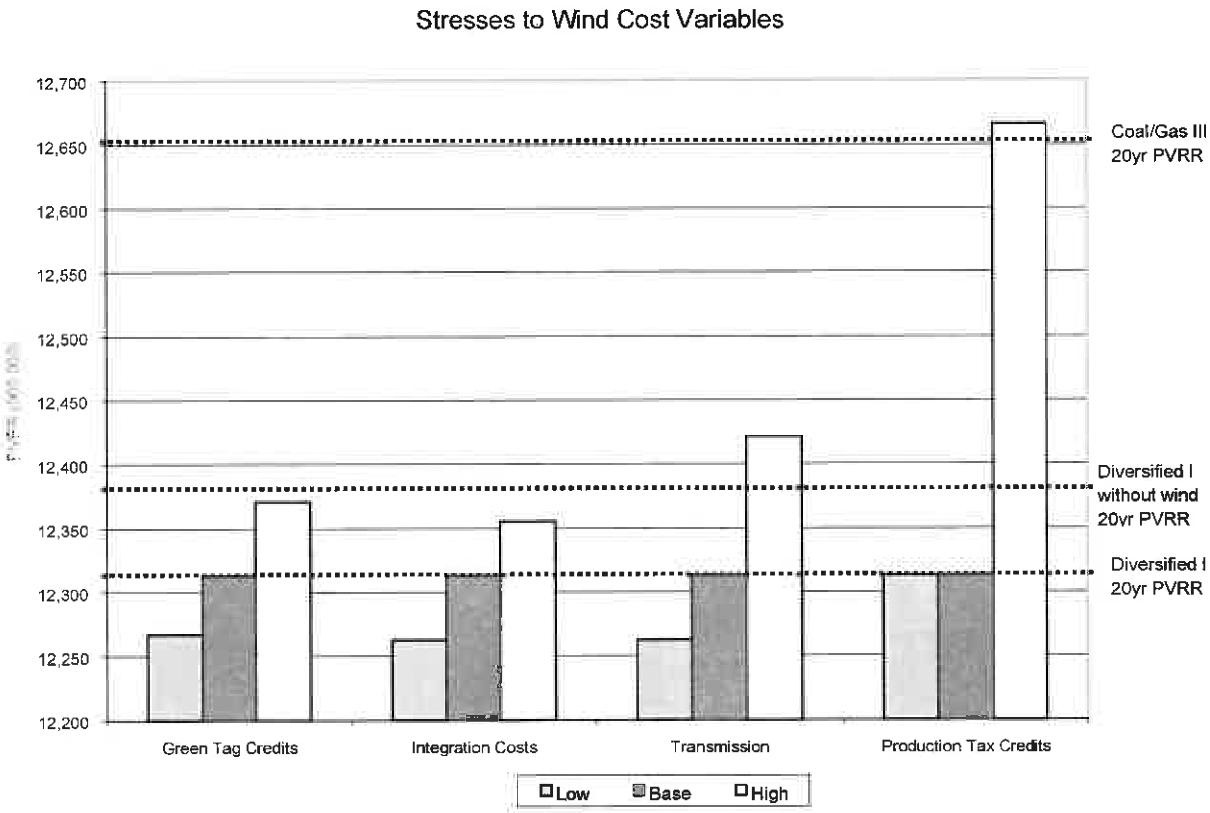
The impact on system operations from adding large variable wind capacity into resource portfolios is unknown. PacifiCorp has begun to quantify the costs of integration by breaking it into two elements, system imbalance, and incremental operating reserves. Appendix J contains the detailed methodology and results from this study. In summary, for 1,000 MW of variable wind capacity in either the East or West sides of PacifiCorp's system, the results of the study estimate integration costs to range from \$5-\$6/MWh.

In the model, it's assumed that integration costs will increase with installed capacity according to the methods determined in the study. For the base case results for each hybrid portfolio, integration costs of the wind resources add \$42 million to the 20-year PVRR. To stress these assumptions, the low end assumption is that integration costs are negligible to the system and at the high end, integration costs are set at twice the estimated base value. This range results in PVRRs +/-0.5% of the base. Due to this relatively small impact on the Diversified I portfolio, system integration costs alone do not impact the financial decisions to add additional wind to the system.

Table 7.9 Diversified I Stress to Renewable Uncertainties

Variable		Low	Base	High	Assumption
Green Tag Credits (\$/MWh)		9	5	0	1st 5 years
	PVRR (\$000s)	12,266,974	**12,313,159**	12,370,888	
	Change from base	(46,185)	-	57,729	
Integration costs		1/2x base	base	2x base	Base = \$5-\$6/MWh
	PVRR (\$000s)	12,271,021	**12,313,159**	12,355,296	
	Change from base	(42,138)	-	42,137	
Transmission		1/2x base	base	3x base	Base = \$4-\$6/MWh
	PVRR (\$000s)	12,262,554	**12,313,159**	12,421,585	
	Change from base	(50,605)	-	108,426	
Production Tax Credits (\$/MWh)		18	18	0	1st 10 years
	PVRR (\$000s)	12,313,159	**12,313,159**	12,665,879	
	Change from base	0	-	352,720	
CO2 Tax (\$/ton)		0	8	40	(see CO2 stress)
	PVRR (\$000s)	12,081,433	**12,313,159**	14,630,030	
	Change from base	(231,726)	-	2,316,871	

Figure 7.22 Diversified I Wind Stresses



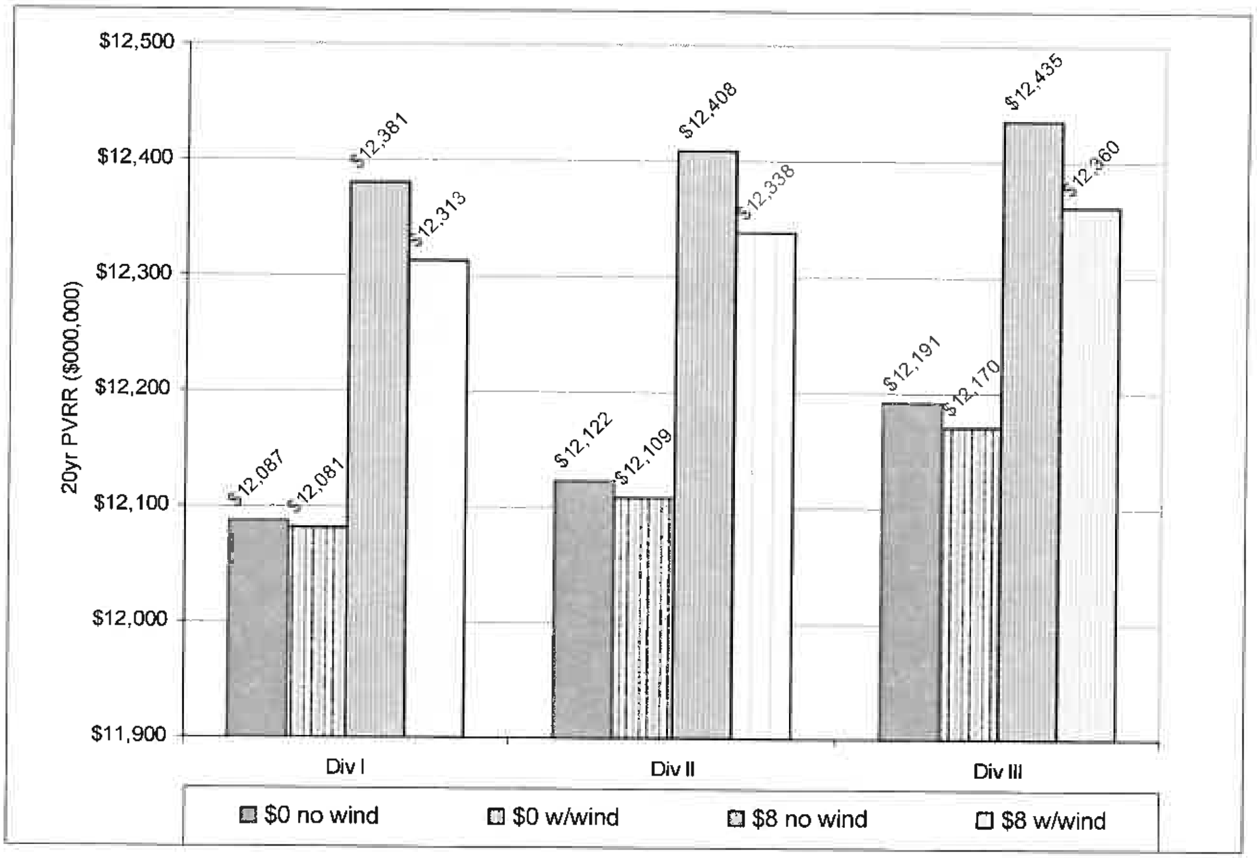
4) CO_2 Allowance Cost

The future of the carbon allowance cost is a federal environmental policy decision beyond PacifiCorp's control but it has potential to greatly impact system operations and long-term resource planning. It is clear that the addition of zero emissions resources to the system when there is a CO_2 allowance cost would most likely have a financial and environmental benefit to the company. This stress tests what the result would be if zero emission resources were added without the policy incentive of a large carbon allowance cost.

The variable wind resource and the $8 carbon allowance cost were removed from Diversified Portfolios 1 through 3. The model run results were then compared to the base case results with wind and $0/ton CO_2 allowance costs. The resulting range of PVRRs rose very slightly (0.04% to 0.17%) without the wind. This stress shows that the addition of wind to the portfolio still produces a reduction to PVRR when there is no carbon allowance cost.

This result was surprising but can be explained by the large reduction in net variable (dispatch) costs, which exceed the costs associated with acquiring the wind capacity. Since the carbon allowance cost is set at zero for both cases, the variable cost reduction is mostly due to the lower fuel use and reduced emissions which produce credits for NOx and SO2 emissions below their cap levels. The wind contract displaces new and existing thermal resources and increases market sales while reducing market purchases. The final substantial cost components, which reduces variable operating costs, are renewable credit adjustments for green tags and the production tax credit. These credits can be classified as offsetting some of the increased variable contract costs associated with acquiring the variable wind resources.

Figure 7.23 Combined Carbon and Wind Stress



The probability of any of these CO_2 allowance cost outcomes is unknown. Model results show that renewable resources can displace thermal resources as a hedge against the high allowance cost scenarios and have little benefit under no allowance cost scenarios.

5) Application of Wind Capacity to Planning Margin

The portion of wind capacity modeled in the Renewable, Alternative Technology I and II, and Diversified I-IV portfolios does not contribute to the planning margin. This very conservative assumption is based on the variability of generation output expected from a wind site that can be 0 MW when the wind speed is too low or too high for energy production.

This assumption was stressed by restructuring Diversified portfolios I, II, and III to attribute 15% of new installed wind capacity towards the 15% capacity planning margin. As a result of this addition to capacity margin, other new resources were decreased an equivalent amount to maintain the 15% system planning margin. To do so, the flat market contract contained in each portfolio was decreased by an amount equal to 15% of the new wind capacity as calculated in the following table.

Table 7.10 Application of 15% Wind Capacity to Planning Margin

15% Wind Capacity Stress										
Diversified Portfolio 1										
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
East Wind Capacity (MW)	0	0	0	200	200	400	400	600	600	720
West Wind Capacity (MW)	0	0	100	100	300	300	500	500	700	700
Total System Wind Capacity (MW)	0	0	100	300	500	700	900	1100	1300	1420
15% Total Wind Capacity (MW)	0	0	15	45	75	105	135	165	195	213

When compared to the base case for results, the system was impacted as follows:

- PVRR decrease of $103-$107 million
- $34-$36 million increase in emissions costs contributing to the PVRR
- 11% increase in West market purchases, 5% decrease in West market sales
- No change to East market activity
- New and existing CCCTs and peakers in the West run at 3-6% higher capacity factors
- Capacity factors of new East CCCTs increase from 48% to 52%.
- East to West transfers increase by 8-13% in 2014 over the base case results, West to East transfers decrease 5-9% by 2014.

15% Wind Capacity - General Conclusions

This analysis shows there is a benefit of approximately $100 million (1%) to overall system PVRR when a portion of wind capacity contributes to planning margin. Less additional generation is needed in the future to meet the planning margin when some percentage of wind output is included in the load and resource balance. With the reduction in new resources, existing resources run harder but not at inefficient levels for their resource type characteristics.

If the built wind capacity did contribute to the planning margin at its expected capacity factor of 32-36%[12], the amount of new capacity installed in the system through 2013 could be reduced by approximately 475 MW. This would reduce the capital investment in the portfolio and lower the overall PVRR. With increased knowledge and comfort of wind operations, PacifiCorp intends to revisit this assumption. Currently, there is not an industry standard for the percentage of wind capacity attributable to planning margins. Further system analysis, including a loss of load probability (LOLP) study, would help to give a reasonable estimate of the impact of wind variability on system operations.

[12] Profiled wind is modeled assuming availability of 32-36% consistent with the historical output of known, wind generation resources.

6) Early Installation of Wind Resources, FY 2005

The modeled wind resources in Diversified I – IV, Renewable, and Alternative Technology I and II portfolios begin installation in FY 2006 at 100MW and grow to 1,420 MW by FY 2013. Since these wind resources do not contribute to the planning margin, the decision to start wind production in FY 2006 was based on the assumed build time for new wind sites including siting, permitting, and construction, not the need for additional capacity. It is possible that new wind resources can be added to the system even earlier than April 2005 if some projects are already in some stage of development.

In this stress case, PacifiCorp assumed each of the wind plant installations could be moved forward one year in the new resource plan. This stress was tested on Diversified Portfolios I – III with the following results:

- Less than 0.2% increase to PVRR ($11-$14 million)
- $6-$7 million decrease in emissions costs contributing to the PVRR
- 3% decrease in West market purchases, 6% increase in West market sales
- 4% increase in East market sales
- No change to unit performance or system transfers

Early Wind Installation - General Conclusions

The decrease in operating costs associated with earlier installation does not offset the increase in time value of costs for acquiring the new resources. The difference is practically insignificant and does not rule out the possibility of entering wind resource contracts before FY 2006. All opportunities for new resources will be evaluated on an individual basis. The model is one representation of a schedule for acquiring new wind resources but the true outcome will be based upon what sites are available and how they fit into the greater system plan.

7) Replace Hunter 4 2012 with IGCC

Integrated gasification combined cycle (IGCC) is a clean coal technology that utilizes a coal gasification process to produce clean fuel gas that can then be used to fuel a combined cycle natural gas turbine. Recognized for achieving slightly lower pollutant emission levels and higher efficiencies than a conventional coal-fired plant, PacifiCorp will continue to follow this technology for future additions as the technology becomes more established and the cost decreases.

In this stress case, the FY 2012 575MW Hunter 4 unit from Diversified portfolio III is replaced by a 370MW IGCC unit at the Hunter location plus a 1x1 CCCT at Mona. The IGCC plant has a more efficient heat rate of 8,311 MMBtus compared to 9,483 MMBtus for Hunter 4 but with this improvement to efficiency is a tradeoff of greater fuel cost, VOM, and a higher outage rate.

This stress was run only on Diversified Portfolios III with Hunter 4 in 2012 and produced the following results:

- 1.4% increase to PVRR ($177 million) due to increased operating costs
- $74 million decrease in emissions costs contributing to the PVRR
- No change to market sales or purchases

- 2% increase in East existing coal capacity factors, 9% increase of new East CCCTs
- Slight increase (2%) in West CCCT Capacity factor to compensate for 13% reduction in East to West 2014 transfers

IGCC vs. Hunter 4 - General Conclusions
The replacement of traditional coal technology at Hunter 4 for IGCC in 2012 would increase overall system costs based on cost information and unit performance characteristics available today. The cleaner technology produces lower emissions but at a higher cost. PacifiCorp will continue to monitor the development of this technology for cost reductions and operational improvements.

8) Replace SCCTs with CCCTs
All the portfolios in this study contain a combination of simple cycle combustion turbines (SCCTs) and combined cycle combustion turbines (CCCTs) which were installed based upon the size and timing of the resource gap, as defined in earlier chapters under portfolio development. SCCTs were mainly added to the portfolios as reserve peakers, providing the capacity to meet the 15% planning margin for the system. Resources were added such that the 15% planning margin was closely met for each year from 2007 through 2013. The peaking units operate between 2-6% capacity factors throughout the first ten years.

The purpose of this stress is to test the impact of gradually adding reserve peakers to the system compared to installing CCCTs up front. Instead of adding small increments of capacity through time in the form of low efficiency reserve peakers, the system resource plan could be redesigned to provide excess (greater than 15%), high efficiency capacity with CCCTs added earlier in the planning process. This methodology results in a heavy up-front build, into which the system demand would grow.

The Diversified portfolio I was first reconstructed by combining the 500MWs of East reserve peakers (200 MW in 2006 and 300MW in 2013) into a FY 2007 CCCT at Mona and replacing the 460MWs of West peakers (230MW 2006 230MW 2012) with a FY 2007 CCCT at Klamath Falls. The following observations were noted when compared to base case results:

- <1% increase to PVRR ($25 million), greater increase to fixed costs than the reduction to variable costs
- $31 million increase in emissions costs contributing to the PVRR
- Increase to market sales and decrease of purchases
- Substantial reductions to CCCT capacity factors, 12% capacity factor in the West, 37% capacity factor in the East.
- 13% reduction in East to West 2014 transfers

Replace SCCTs - General Conclusions
Replacing SCCTs with CCCTs in early years results in a capacity planning margin greater than 20% through 2011. Along with this high level of build is an increased reliance on the market for sales of excess generation. The financial tradeoffs of increased capital from early investment is not fully compensated by the increase in market sales and reduced use of less efficient units causing the PVRR to remain slightly higher than the base case. The resulting capacity factors of

the CCCTs in both the East and West decrease substantially such that the performance of existing CCCTs is more characteristic of an SCCT. At this level of capacity planning margin, retaining the peaking type resources for reserves seems beneficial due to the lower reliance on a sale market and more optimum use of new and existing resources.

9) Timing of Large East Units

Common to all top four portfolios are three large base-load type units in the East. These units include the Gadsby Repower, Mona CCCT, and Hunter 4 options. This study determined that the unit timing of Diversified portfolio I with Hunter in 2008, Gadsby in 2009 and then Mona in 2012 yields the least cost. PacifiCorp recognizes that the many Paradigm risks and industry scenarios could greatly impact future resource decisions including installation and fuel type. The purpose of this stress is to quantify the impact to PVRR from shifting the timing and type of these three large resources.

Two portfolios were used for this stress test, Diversified I and Diversified III. Recall that Diversified III installs three major units in years 2007, 2009, and 2012 and Diversified I plans for units in 2008, 2009, and 2012. The following table illustrates the timing variations studied. Scorecard results for these model runs are in Appendix E, Table E.13.

Table 7.11 Resource Timing

Portfolio Name	Case	2007	2008	2009	2012	PVRR ($billion)	% change
Diversified I	Base		Hunter 4	Gadsby	Mona	12.313	0.00%
	Variation 1		Gadsby	Hunter 4	Mona	12.325	0.10%
	Variation 2		Gadsby	Mona	Hunter	12.317	0.03%
	Variation 3		Gadsby	Mona	Mona	12.395	0.67%
Diversified III	Base	Gadsby		Mona	Hunter 4	12.360	0.38%
	Variation 1	Gadsby		Hunter 4	Mona	12.371	0.47%

The following observations were noted when comparing each variation to the corresponding base case results:

- Variations produce a <1% increase to PVRR ($4-$82 million)
- Installing the first unit in 2008 vs. 2007 provides the greatest reduction to PVRR, regardless of fuel type
- Variations with Hunter 4 in later years show greater benefit in emissions reductions.
- Market activity is unchanged
- Unit capacity factors and system transfers by 2014 are unchanged

Timing of Units - General Conclusions

Diversified I contains the least cost resource mix. Alternatives to the timing of large resources negatively impact the 20-year PVRR. However, cost changes ranged by less than 1%. While the Diversified I configuration is superior, the difference could arguably be described as statistically insignificant. Due to the small magnitude in PVRR difference between portfolios, the Action Plan for acquiring resources can remain flexible without sacrificing a statistical advantage.

10) Hydro Licensing Impacts

A large percentage of PacifiCorp's hydro resources are involved in some stage of the re-licensing process. In this stress case, PacifiCorp assumed approximately 200 MWs (18%) of owned hydro resources are not successfully relicensed. The 200 MW is a combination of run-of-river and peaking resources in the West control area. These resources are removed and replaced by two additional SCCT peaking units totaling 230 MW. This stress models the impact of losing an existing low cost resource and replacing it with resources with similar capabilities.

This stress was run on Diversified portfolios I - III. When compared to the base case for results, the system was impacted as follows:

- PVRR increase of $608 million due to increase in capital and operating expenses
- $20-$22 million increase in emissions costs contributing to the PVRR
- 16% increase in West market purchases, 8% decrease in West market sales
- No change to East market activity or unit performance
- New and existing CCCTs and peakers in the West run harder
- East to West transfers increase by 11-22% in 2014 over the base case results, West to East transfers decrease 5-15% by 2014.

The new, replacement resources required to meet this resource's profile tend to be more expensive to run relative to market purchases and imports of excess East generation. Therefore, West purchases and East/West transfers increase to cover West load.

Hydro Licensing - General Conclusions

This analysis shows hydro to be a valuable system resource. With the loss of 200 MW of hydro resources, units operate at higher capacity factors and spot market purchases increase in the West. The East assists the West by transferring more and receiving less. Hydro is a flexible low cost resource which meets PacifiCorp's system needs well.

The IRP assumes all owned hydro plants would be relicensed. Detailed, plant-specific hydro analysis would be required prior to changing this assumption. This will be done as plant relicensing occurs.

11) Loss Of Load – 400 MW In Oregon (SB 1149 Potential Impact)

The major assumption for this stress case is that with restructuring legislation (SB 1149), PacifiCorp may lose some commercial and industrial customers in Oregon. For purposes of stress testing, an assumption was made that approximately 400 MW of flat commercial and industrial load are removed from the West Main transmission area in July 2003.

To reflect this loss, the model was adjusted to remove 400 MW from the load each hour and the mix of resources in the Hybrid portfolios was reduced to reflect a decrease in capacity requirement. Only new resources in the West were removed for this stress case along with their associated transmission costs. Portfolio resource reductions include the following. The 500 MW off-peak contract which is present in every portfolio and expires in 2006 was reduced to 400 MW, the 2007 2x1 West CCCT was reduced to a 1x1 and the 230MW of new peakers in the

West for 2006 were removed. Even with these resource reductions, the portfolios still attain a 15% planning margin requirement.

In addition to adjusting the portfolio resources for loss of load, system transmission capabilities would also have to be reduced. This step will require further analysis with more detailed assumptions for customer load factors and locations. Due to the complexity of these adjustments, this analysis was completed with the loss of load and resource adjustment but will require further analysis for transmission impacts. The results are considered preliminary.

Compared to the base case scorecard results for the Diversified I – III portfolios, system operations are impacted as follows:

- PVRR decrease of $1.78 billion due almost entirely to reduction in variable operating costs. Only $350 million of the reduction is due to capital costs.
- $80-87 million reduction in emissions cost contribution to PVRR
- Purchases in the West decrease 40% and West sales increase 20%
- East new and existing resources operated at slightly lower capacity factors
- West new and existing CCCT capacity factors greatly decreased

The PVRR results for the scorecard comparison do not determine if the loss of load would be beneficial or detrimental to the system. The best method of evaluating the system performance is by looking at the 20-year, weighted average variable power and incremental fixed costs on a $/MWh basis before and after the loss of load. Table 7.12 shows the comparison of before and after $/MWh. In summary, the loss of load resulted in a $1.30/MWh reduction in incremental system costs. These preliminary results do not include the system impacts due to reduction in transmission capabilities.

Table 7.12 Loss of Load Comparison

Portfolio	Base $/MWh	Stress* $/MWh	Difference $/MWh
Diversified I	15.26	13.96	1.30
Diversified II	15.28	13.97	1.31
Diversified III	15.31	13.99	1.32

*These results do not include impacts to existing transmission

Loss of Load - General Conclusions

The loss of a flat block of load in Oregon greatly impacts West operations but does not significantly impact the East, other than providing more transfers into the East system. The overall PVRR is greatly reduced but change to system costs on a $/MWh basis provide a more meaningful summary of impact due to the stress situation. These results show that the loss of load reduces incremental $/MWh costs. This result is preliminary since it does not include an adjustment for impacts to transmission capabilities associated with these customers. The West is still considered slightly overbuilt in this scenario since market sales increase, purchases decrease, and unit capacity factors are reduced. In 2007, when the large long-term purchase contracts expire, it is unlikely there would be a need to build with this magnitude loss of load. More likely, PacifiCorp would continue to purchase long-term contracts. An option would be to build or buy smaller resources as modeled through this stress.

12) DSM Decrement

Modeling Results

The effect of increasing the amount of DSM was tested. Since DSM reduces load, the effect of increasing DSM is called the DSM decrement. The nominal results of the DSM decrement runs through 2012 are summarized in Tables 7.13 and 7.14.

For each decrement case, the Revenue Requirement of the Diversified portfolio I containing the base load forecast was compared on a year by year basis with the new decrement case Revenue Requirement with the load decrement. Appendix G details how these decrement runs were designed and includes their detailed results.

Table 7.13 compares the break-even incremental $/MWh value of potential Class 2 DSM programs for the first few fiscal years for each decrement. These values were calculated for the entire planning period and can be found in Appendix G.

Table 7.13 Decrement Results Summary (nominal $/MWh) For Class 2 DSM Programs

Decrement Case	2004-2008	2009	2010	2011	2012
D150-10	Decrements begin in FY 2009	234	188	189	181
D300-20		93	91	85	57
D150-40		60	54	53	41
D300-60		50	48	49	51

These nominal decrement value results per MWh can be compared to the nominal market prices per MWh for those same years from Table C.25:

Table 7.14 Nominal Market Prices

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Market Prices	30.84	32.29	32.68	33.54	37.34	43.15	38.66	41.58	47.69

As load factors increase, the break even program costs decreased.

The 1% load factor decrements model a load control type of Class 1 DSM program. Since the PROSYM model cannot dispatch load decrements, these decrements were selected based on peak load days in one year, and the same days repeated over the duration of the planning period. The nominal decrement value of these decrements is shown in the Table 7.15 over the first few years of the decrement period. Model results for the entire planning period can be found in Appendix G.

Table 7.15 Decrement Results Summary (nominal $000) For Class 1 DSM Programs

Decrement Case	2004-2008	2009	2010	2011	2012
D150-1	Decrements begin in FY 2009	9,887	9,605	7,607	8,853
D300-1		10,197	9,663	8,415	9,777

One 100MW East reserve peaker was removed from 2006 for each of these model runs.
These 1% load factor decrement values reflect the break-even nominal value in each year of the capability to curtail loads by 150 MW and 300 MW respectively. PacifiCorp should not pay more than the lessor of these values or a like market instrument for this load interruptability.

DSM Decrement General Conclusions
This study provided preliminary guidance in the future design of DSM programs for the system. Focus should be given to lower load factor programs that match peak without excluding opportunities to conduct programs with higher load factors.

Actual program designs, as they build to higher annual DSM levels (above the base 15 MWa /year) for FY2004 and beyond, will be run through the model and the nominal Revenue Requirements will be compared to the base revenue requirements. A bundle of programs achieving an additional 300 MWa over 10 years that can be implemented with a reduction in revenue requirements using this decrement analysis will be cost effective. Distribution benefits, because they are very local and specific to load characteristics in a distribution area, will be considered as individual programs are designed.

This modeling effort can not determine the feasibility of achieving 450 MWa of DSM in the PacifiCorp service territory over the next 10 years. The Action Plan includes an effort to determine the actual, realistic market potential for DSM in the PacifiCorp service territory. Future goals may be adjusted to reflect actual market potential.

13) Reducing the Planning Margin
The initial portfolios were built to meet a 15% planning margin. The effects of reducing the planning margin from 15% to 10% were originally tested on the following portfolios: Gas/Coal I, Coal/Gas III, PacifiCorp Build II and All-Gas II. It is expected that the impact of planning margin reductions would be similar on other portfolios including the Renewable and four Diversified Portfolios. Comparisons between portfolios with very similar resource blends built to different planning margins show the impacts to system reliability, costs and risks associated with varying levels of available resources.

PacifiCorp's needs are met with a slightly different mix of generation when moving from a 15% to a 10% planning margin. The lower margin changes the level of emissions, market purchases and sales, unit capacity factors and East-West energy transfers. The effect of the lower margin in megawatts added by 2013 is between 500 and 550 MW.

The Scorecard for the portfolios with a 10% Planning Margin is included in Appendix E, Table E.3.

PVRR
A lower margin (from 15% to 10%) is shown to consistently reduce the 20-year PVRR by between $100 million and $325 million, or between 0.8% and 2.5%. A major factor in this cost reduction is a reduction in present value levelized fixed costs of between $300 and $375 million (12-17%). This is partially offset by an increase in net electricity costs. In the all-gas portfolios the reserve margin reduction yields $330 million savings in PVRR levelized fixed cost, offset by an increase of $220 million in PVRR of net electricity cost. In contrast the Diversified Gas/Coal I portfolio shows a $375 million reduction in PVRR levelized fixed cost, but only $50 million increase in PVRR of net electricity cost.

Emissions
The level of emissions from PacifiCorp-owned resources will not materially change when moving from a 15% to 10% planning margin. The reduced capacity results in higher peaking unit use and additional market purchases over the 15% case. NO_x and SO_2 emissions increase only slightly. CO_2 and Hg emissions should not change.

Unit Capacity Factors
As mentioned, the major differences in supply under a 10% planning margin come from additional market purchases and increased peaking unit usage. The capacity factors of non-peaking units remain consistent.

Market Sales and Purchases
Market purchases will increase by a moderate amount when implementing a 10% planning margin. The scorecard shows that 10-year average purchases (2004-2013) are expected to increase by less than 10 MWa. A snapshot of any year beyond 2013, after all resources in the IRP have been installed, shows that annual purchases in the East increase by approximately 10%. West purchases increase by closer to 6%.

PacifiCorp's market sales decrease with the decreased availability of assets from which to sell.

East West Transfers
The effect of a 10% planning margin on East-West transfers will depend upon how the reduction in capacity is implemented. If the 10% planning margin is accomplished via an equal reduction in planned peaking units in both the East and West control areas, West-to-East transfers will increase marginally (typically in the 5% range) in a diversified portfolio versus the 15% planning margin case.

Contingency Market Purchases
PacifiCorp understands that less routine events, such as multiple unit outages, low hydro availability or high load, occur, and has therefore incorporated in its modeling the ability to access the electricity markets on a contingency basis. For modeling purposes, these electricity purchases are available as a resource under unusual operating conditions – used only after owned assets (and regular markets) have been exhausted. However, energy available from this source is limited. The market size approximates 15% of an area's peak load.

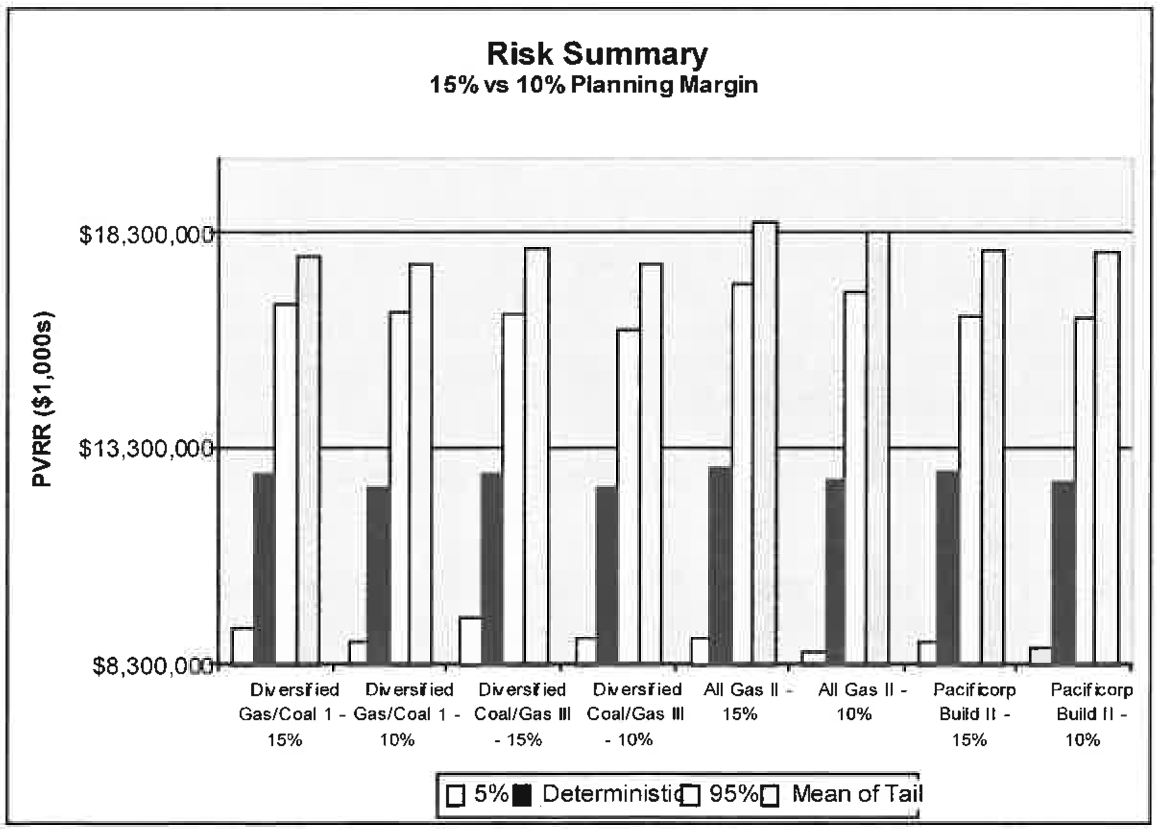
In the portfolio runs with a 15% planning margin, contingency markets were typically relied on for about 1,000 MWh/year (or about 0.002% of total annual system load) – due to randomly occurring multiple forced outages. This is a very low level of contingency market participation.

A 10% planning margin will require slightly higher contingency market participation. The portfolios tested with a reduced planning margin generally purchased about 7,000 MWh/year (or about 0.01% of total annual system load) from the contingency markets.

Risk and Planning Reserves

Figure 7.24 graphically demonstrates the effect of changing planning reserve margin requirements. It compares PVRR, 95th and 5th percentile PVRR as well as the mean of the tail for pairs of portfolios that have a 10% and 15% planning margin. The observations for the 15% planning margin are higher for each measure. Given the additional capital costs of building to a higher planning margin, this should not be surprising.

Figure 7.24 Planning Margin Comparison



Reserves, if effectively deployed, should reduce risk. Although all measures for 15% portfolios were higher, the additional cost may be acceptable if risk is improved by a greater margin. Figure 7.25 attempts to convey this issue. It illustrates that risk is reduced.

Figure 7.25 Differences Between Planning Margins By Category

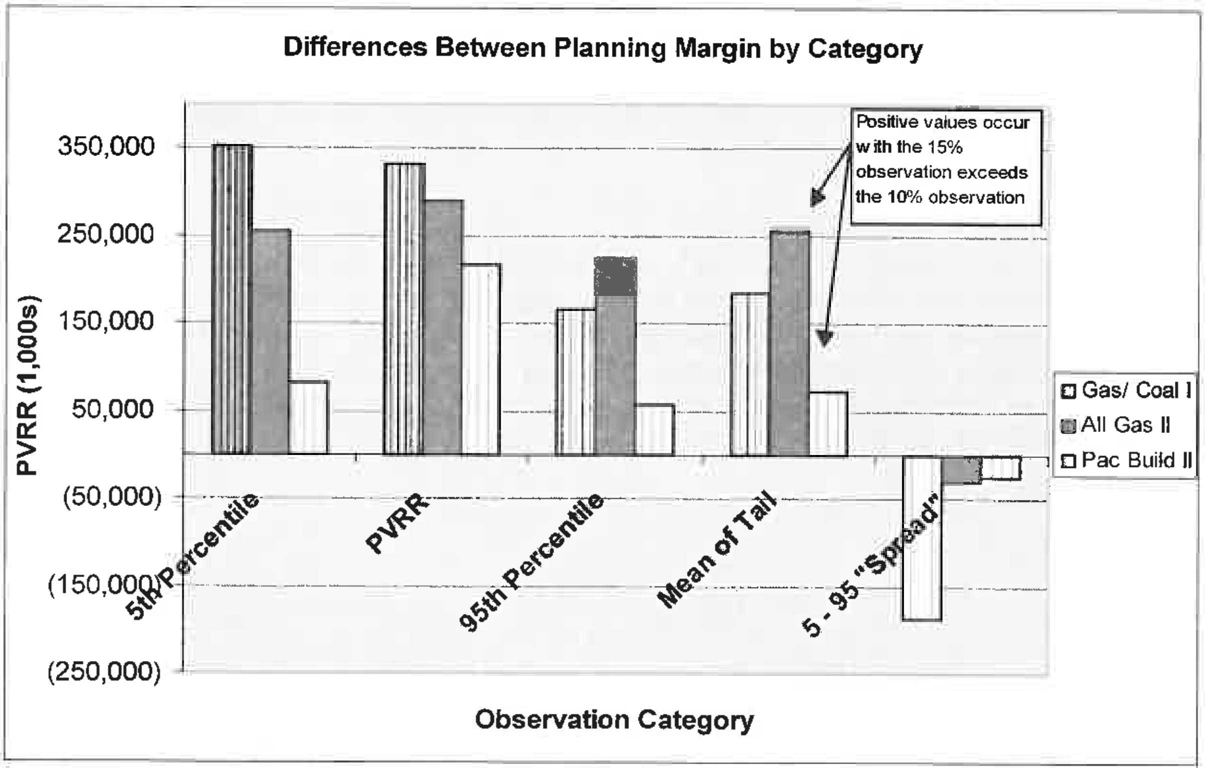


Figure 7.25 demonstrates that additional planning margin reduced risk. Observe the 5% - 95% Spread. This measure begins by taking the difference between the 5th percentile and the 95th percentile for each portfolio. The difference approximates the range of expected outcomes, a reasonable representation of risk. Next the 5% - 95% Spread is determined by subtracting the calculation above for the 10% portfolio from that found for a 15% portfolio. As expected, the 5-95 spread for each 10% portfolio exceeded that of its 15% counterpart. Thus, the risk or range of expected outcomes under 10% planning margin portfolios is greater than that of the 15% planning margin portfolios.

Now observe the relative size of the expected PVRR as plotted on Figure 7.25 and the corresponding 5% - 95% Spread. The difference between the PVRRs of the two portfolios is much greater than the difference between the 5% - 95% Spread measurements. If the additional reserves adequately offset risk, the reduction in risk (represented by the 5% - 95% Spreads) should equal or exceed the expected investment needed to realize it (represented by the PVRR). Therefore, it can be tentatively concluded the dollar investment in the added resources is not accompanied by a commensurate reduction in risk.

The above risk conclusions are tentative for the following reasons.

- This is a 20-year study assessing investments of billions of dollars. While certain observations appear different, it could be reasonably argued that the study is necessarily too blunt an instrument to confidently distinguish relatively smaller differences among observations.

- While the risk reduction does not appear favorable compared to the investment needed to realize it, the investment is not without merit. The adequacy of an investment-risk tradeoff is somewhat subjective. Different people, different states and different groups have different sensitivities and preferences for risk.

Reduced Planning Margin Conclusion

While the appropriateness of the capital - risk tradeoff remains to be resolved, the decision to build to a 10% or 15% planning margin will be subject to regional policy issues like RTO and SMD. Fortunately, the build time required to install additional capacity neatly overlaps the proposed resolution times of these issues. Current developments could be delayed or future acquisitions eliminated to conform the plan to the then current SMD requirement. Clarity on RTO and SMD should be achieved before PacifiCorp can build to a 10%, much less 15%, planning margin.

8. CONCLUSIONS

OVERVIEW

The goal of this Integrated Resource Plan (IRP) is to develop a clear plan and strategy which will help ensure:

- PacifiCorp fulfills its obligations to serve its customers
- PacifiCorp delivers the most economic solutions for both its customers and shareholders
- The risks to the customers and to PacifiCorp are reduced
- A high level of stakeholder concurrence with PacifiCorp's resource plans and implementation decisions is obtained

The markets in which PacifiCorp operates are continually developing and changing. It is critical that the plan and actions arising from this IRP lead to a solution which allows PacifiCorp the flexibility to adjust to the changing operational environment and at the same time provide as much certainty and stability as possible for PacifiCorp and its customers.

This Chapter summarizes the main conclusions and key findings outlined in the report from which the Action Plan (Chapter 9) is developed.

PORTFOLIO SELECTION

PacifiCorp's current position (Chapter 2) reveals a substantial need for new resources. This gap analysis also outlined how the two control areas, PacifiCorp West and PacifiCorp East, have different resource and transmission issues. This difference results in a different balance of loads and resources for each side of the system. Resolving the gap economically and reliably was the focus of PacifiCorp's planning process.

The analysis of the analytical results (Chapter 7) confirm that the Diversified Portfolio I is the least-cost, lower risk portfolio to fill PacifiCorp's long-term resource needs based on the forecasted customer demand.

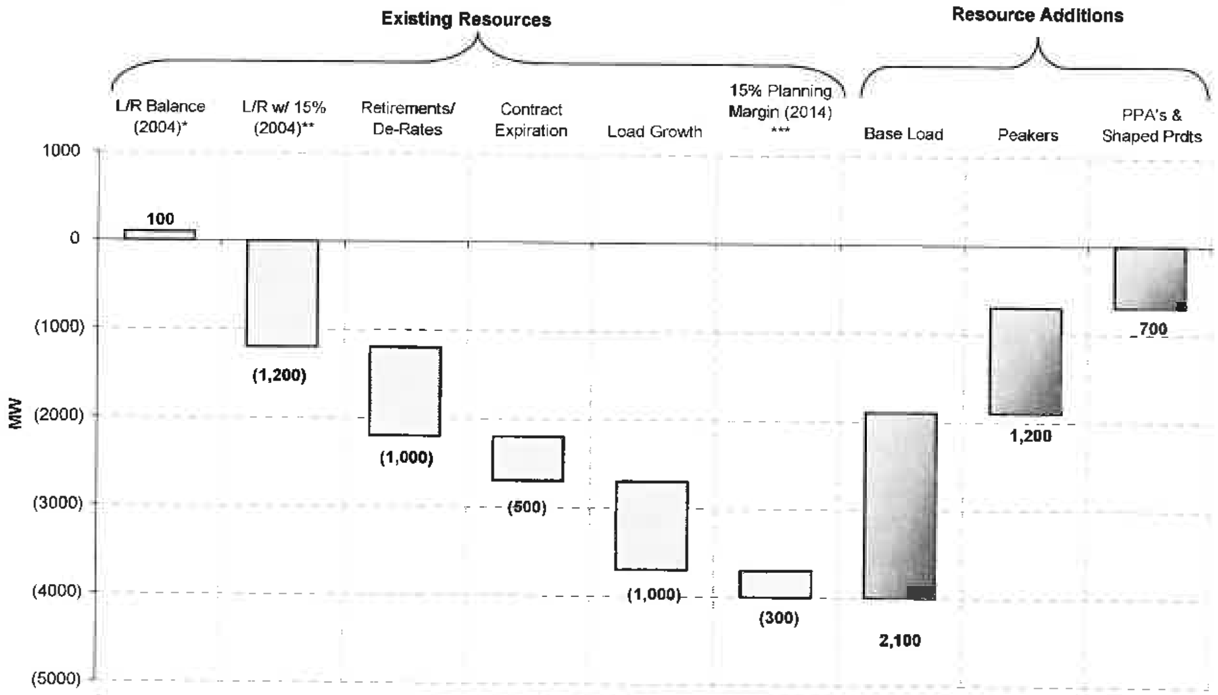
Table 8.1 is a summary of the total MW, timing and capital cost associated with specific resources contained in Diversified Portfolio I. A more comprehensive summary of this portfolio can be found in Appendix D.

Table 8.1 Diversified Portfolio I Resource Addition Summary

Location	Resource	Total MW	Fiscal Year Installed	Capital Cost (MM $2002)
East	Class 1 DSM	91	Programs Begin in 2004	0
	Class 2 DSM	123	Programs Begin in 2004	0
	Super Peak Contract	225	From 2004-2007	0
	Thermal Contract	175	Incremental 25 MW purchases beginning in 2006	0
	Peakers	700	200 MW – 2006 500 MW - 2013	360
	Wind	720	200 MW – 2007 200 MW – 2009 200 MW – 2011 120 MW – 2013	720
	Coal Base Load (Hunter 4)	575	2008	800
	CCCT (Gadsby Repower)	510	2009	310
	CCCT (Mona)	480	2012	340
West	Class 2 DSM	22	Programs Begin in 2004	0
	Flat Off-Peak Contract	500	From 2004-2006	0
	Thermal Contract	175	Incremental 25 MW purchases beginning in 2006	0
	Peakers	460	230 MW – 2006 230 MW - 2012	220
	Wind	700	100 MW – 2006 200 MW – 2008 200 MW – 2010 200 MW – 2012	700
	CCCT (Albany)	570	2007	325
	Flat Contract (7x24)	200	2011	0
	Peaking Contract	100	2012	0

Figure 8.1 illustrates how the resources in the Diversified Portfolio I fill the capacity requirement for the 2004 to 2014 time period. The Class 1 and Class 2 DSM programs in Diversified Portfolio I have been included as a decrement to the load forecast, which is used in the calculation of the L/R balance. Since PacifiCorp assumed no capacity credit for wind, the wind capacity in the Diversified Portfolio I is not included in this figure.

Figure 8.1 IRP Capacity Requirement Breakdown –Rounded to the Nearest 100 MWs



* L/R Balance is PacifiCorp's total resources less its total peak requirement
** L/R Balance with 15% planning margin requirement
*** Incremental planning margin requirement by 2014

DEMAND-SIDE MANAGEMENT

There are 450 MWa of cost effective Class 2 DSM and 100 MW of Classes 1 and 3 DSM expected over the first ten years of the plan. An estimated 90 MW of interruptible load control capacity is implemented during fiscal years 2004 to 2006. Additional cost effective DSM will be reviewed and implemented where possible during the period.

Table 8.2 highlights timing and size of the Class 1 and Class 2 DSM programs identified. These programs are included in all of the portfolio runs and are marked with an 'A' in the first column of the table. The Class 1, 2 & 3 DSM programs marked with a 'B' in the table, were the hypothetical DSM programs tested in the DSM decrement analysis discussed in Chapter 7 and Appendix G. Actual programs need to be identified and designed for PacifiCorp to achieve higher annual DSM levels beyond the programs in the base portfolio runs.

Table 8.2 Planned DSM Over the Period 2004 to 2013.

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
A	Class 1 DSM (load control – peak MW Capability)	30	60	91	91	91	91	91	91	91	91
A	Class 2 DSM (cumulative MWa)	35	49	62	76	90	104	118	132	144	144
B	Class 1 & 3 (load control and curtailable tariffs – peak MW)	-	-	50 – 100 MW							
B	Class 2 DSM	-	-	150 – 300 MW							
Notes: A – Base DSM in every portfolio , B –DSM associated with decrement analysis											

The modeling effort does not determine the feasibility of achieving 450 MWa of DSM in the PacifiCorp territory over the next ten years. The additional planning decrement resource addition of 300 MWa (above the base 144 MWa) was not included in the final portfolio resource plan because specific cost effective programs to fill the 300 MWa decrement have not yet been identified. To evaluate the cost effectiveness of this additional DSM, the value of the reduction in the load forecast (the decrement) needs to have a resource mix that can be changed once the actual decrement containing program designs have been included. A new load/resource balance will also need to be produced, with supply side resource timing changed because of the load decrement (the capacity deferral value of the decrement). The action plan will include steps to assess the feasibility of an additional cost-effective 300 MWa of DSM resource including a market assessment study, design of additional programs and an RFP to find effective programs from the marketplace. Future goals may be adjusted to reflect actual market potential.

RENEWABLES

As mentioned in Chapters 5 and 6, the portfolios that were developed in the beginning of the analysis contained wind resource additions in line with the proposed Federal Renewable Portfolio Standard (RPS). These additions were modeled as electricity purchase flat contracts for 1,146 MW of wind generation planned from 2003 through 2013 and charged at $50/MWh.

In the final portfolios, the $50/MWh flat contract was replaced with "profiled wind", i.e. wind whose profile follows an anticipated, more realistic production shape. Under profiled wind, energy deliveries are anticipated to differ in each hour of the day. This profiled wind has been included based solely on its economic merits. Table 8.4 provides a breakdown of the wind build pattern in Diversified Portfolio I.

Table 8.4 The planned Wind build up in Diversified Portfolio I

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
Wind East			200		200		200		120	720 MW
Wind West		100		200		200		200		700 MW

Solar and geothermal opportunities will also be examined on a case by case basis for economic merit and inclusion in PacifiCorp's overall resource portfolio.

PEAKING UNITS

Diversified Portfolio I requires up to 1,200 MW of peaking capacity be added over the plan period 2006 to 2013 (the equipment market and economics will dictate the actual technology used). Peaking resources are a necessary component of every portfolio, and serve two purposes. One is to meet the load shape requirements for both the East and West sides of PacifiCorp's system, and the second is to meet the capacity requirements of the 15% planning margin. Prior to commitment to build these assets, Purchased Power Agreements (PPAs) and shaped product opportunities will be reviewed and compared for economic benefit, risk reduction and long term optionality.

There remains uncertainty surrounding the planning margin requirements outlined in the proposed SMD. PacifiCorp has designed the action plan based on a 15% planning margin. However, it will take a number of years to build to a significant planning margin (even to 10%). This period will allow PacifiCorp time to modify its plans in concurrence with the future requirements of SMD. Further study of an appropriate planning margin for PacifiCorp will continue, and is an element of the Action Plan.

BASE LOAD UNITS

In line with the load growth, plant retirement and contract expiration, an estimated 2,100 MW of base load capacity is required. As with peakers, the need for additional base load capacity was observed in Chapter 7 and found in every portfolio. Three base load units in the East (in service in 2008, 2009 and 2012) and one unit in the West (in service in 2007) will be further researched and pursued. Here the process of sizing and selecting resources consistently identified base load as having desirable least-cost characteristics.

For IRP modeling purposes, and in line with the market depth and liquidity issues discussed in Chapters 1 and 3, it is assumed that they will be physical assets. However, these units could feasibly be replaced with a long term PPA. Prior to commitment to build any of these assets, PPAs or other asset purchase opportunities will be reviewed and compared for economic benefit, risk reduction and long term optionality. This Procurement Program is discussed in the Action Plan.

SHAPED PRODUCTS AND POWER PURCHASE AGREEMENTS

Diversified Portfolio I required approximately 700 MW of shaped products or PPAs throughout the plan period 2004 to 2013. These contracts will fill an immediate short term peaking need in the East, prior to any assets being built and will supplement the building of additional assets in the long term. Shaped products and PPAs also aim to cover off-peak requirements in the West.

The 700 MWs are in addition to any alternative shaped product or PPAs that may be entered into in relation to the Peaking and Base Load requirements mentioned above.

TRANSMISSION

Transmission additions are requested to support all the assets detailed in the Diversified Portfolio I. Several upgrades feeding into the Wasatch Front area, specifically the "Wasatch Front Triangle", should be implemented immediately (see transmission section in Chapters 5). Additional transmission is necessary to support the new resource additions in Diversified Portfolio I.

This analysis will depend on the as yet unknown outcome of the RTO process. Because of RTO, it is possible that there will be greater potential for additional transmission than is currently suggested by the portfolios. While the modeling process demonstrated that under current assumptions large additions of transmission unrelated to new resources are unwarranted, the RTO Paradigm Risk could change that finding. Further study and attention to developments will be required to determine the RTO West impact and influence.

The transmission associated with the development of the renewables portion of the portfolio requires further clarification. The detail of the transmission requirement and the potential impact on the system performance will be defined when the potential sites are determined.

COAL VERSUS NATURAL GAS

Overview

The portfolio results clearly show PacifiCorp needs to add base-load resources. The least cost portfolio includes a coal based thermal unit in the East. Coal-fired generation may be particularly advantageous when procuring resources in the Rocky Mountains because coal is an abundant indigenous resource there. However, the long-term impacts of atmospheric emissions are casting doubt on the viability of coal-fired generation. The IRP least cost portfolio is dependent upon the impact of a number of these paradigm risks, including air emission standards and possible global warming measures. PacifiCorp believes it has adequately addressed these risks, based on our current understanding of them, and coal plants remain a low-cost option. The IRP Action Plan includes further work to develop and test the viability of a coal base thermal unit, including an ongoing assessment of the risks.

Coal Cost Advantage

Among the four diversified portfolios, which were the top four portfolios based on lowest PVRR and least risk, Diversified Portfolio IV excludes coal-fired generation, while Diversified Portfolios I, II, and III all include a 575 MW base-load coal unit in Utah. In relative terms, all of the Diversified Portfolios provided similar PVRRs over the 20-year plan horizon. The differences between these top four portfolios range from 0.2% to 0.7% above Diversified Portfolio I. Given the time period of the study and the large number of inputs considered, these differences could arguably be described as statistically insignificant.

This same relative advantage of new coal holds in the risk results as well. A greater sensitivity to natural gas price fluctuations makes Diversified Portfolio IV prone to high PVRR outcomes during high loads and high natural gas price iterations. Exposure to natural gas appears to be a leading contributor to the risk differences in the portfolios. The Diversified Portfolio I featuring the addition of a coal plant with the earliest installation schedule has the least natural gas exposure.

Environmental Cost Risk

Since base-load coal generation produces more CO_2 and other air emissions per megawatt-hour of energy, the effect of increasing the cost of emissions is to reduce the cost advantage of coal. Examining the CO_2 stresses reveals this effect. Using the PVRR as a measure, Diversified Portfolio I placed first at the $0, $2, and $8/ton CO_2 allowance costs. Somewhere between $8/ton and $25/ton the merit switches to Diversified Portfolio IV with Diversified Portfolio II placing second. This analysis provides the general conclusion that as the CO_2 caps lower and the allowance cost rate increases, the portfolio without the coal plant becomes the least-cost portfolio based on PVRR.

Benefits to a portfolio without a coal plant addition is not limited explicitly to CO_2 related costs. Other pollutants follow course with the CO_2 trend, decreasing as the incremental allowance cost increases are applied. Greater clarity on carbon allowance cost issues, as well as cost issues related to all pollutants, would be helpful prior to selecting a fuel type.

Timing of Coal Addition

In Chapter 7, a stress was performed (Stress 9 – Timing of Large East Units) to test the timing of the two natural gas plants and the coal plant that was in Diversified Portfolios I, II, and III. This study determined that the unit timing of Diversified Portfolio I with the coal plant (Hunter 4) in 2008, Gadsby in 2009, and then a natural gas plant at Mona in 2012 yields the least cost solution. The differences between the PVRR results of Diversified Portfolio I and changing the timing of these three base load units is less than 1%. Therefore, the differences between the portfolios that adjust the timing of the base load units could arguably be described as statistically insignificant.

Coal Versus Natural Gas - Conclusions

Results appear to favor adding a new coal unit, though with some ambiguity, especially with regard to timing. The preferred timing could also be influenced by the resolution over time of uncertainties, some of which contribute to the ambiguity of results. Over the next three to five years, there may be more certainty with regard to future environmental costs, especially costs of CO_2 emissions, better knowledge of the cost and performance of clean coal technologies that could reduce exposure to environmental risks, and a better picture of the level and volatility of future natural gas prices. Finally, more information can be obtained regarding direct compliance costs and potential offset costs of a specific new coal unit. Though only with the undertaking of specific siting and environmental permitting activities.

This is not an either/or choice of coal versus natural gas, however. Even those portfolios that most heavily favor a new coal unit also require new base-load natural gas CCCTs in the same

2007-2009 time frame. Thus, siting and licensing of both new CCCT and base-load coal are warranted and not mutually exclusive. A new base-load coal unit at Hunter 4, the practical alternative considered in the portfolios described above, could be a valuable portfolio addition somewhere in the 2008-2012 time frame, under most future conditions. However, it can be a realistic alternative in this time frame only if siting and environmental permitting activities prove out its merits.

9. ACTION PLAN

This chapter provides details of the IRP Action Plan that PacifiCorp intends to implement following a fully acknowledged IRP. PacifiCorp requests that each State Commission acknowledge and support the IRP, including acknowledgement of the Action Plan, in accordance with Commissions' requirements for an IRP.

Included in this chapter are:

- The detailed Action Plan, including specific Findings of Need and Implementation Actions
- The Decision Processes for implementation of the Action Plan
- The Procurement Program for implementing the Action Plan
- An update on PacifiCorp's Current Procurement and Hedging Strategy
- Description of how PacifiCorp Resource Planning and Business Planning are aligned
- Discussion on the Action Plan's consistency with the Oregon's restructuring legislation (SB-1149)

THE IRP ACTION PLAN

The Action Plan arising from this IRP is based on the single least cost, low risk portfolio arising from the analysis results discussed in Chapter 7 and the conclusions summarized in Chapter 8. The Action Plan portfolio is the Diversified Portfolio I (DPI). The resource make up of DPI for the period 2004 to 2014 is as follows:

- 1,400 MW Renewables
- 1,200 MW Peakers
- 2,100 MW Base Load
- 450 MWa DSM
- 700 MW Shaped Products

The Action Plan aims to ensure PacifiCorp will continue meeting its obligation to serve its customers at a low cost with manageable and reasonable risk and at the same time remain adaptable to changing course, as uncertainties evolve or are resolved, or if a Paradigm shift occurs. Given the historical variability and future uncertainty, this represents the least-cost IRP solution. An element of the Action Plan is to preserve PacifiCorp's optionality and flexibility in the future.

The IRP is intended to provide guidance and rationale for PacifiCorp's resource planning path forward. 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 this IRP Action Plan.

This Action Plan is based upon the best information available at the time the IRP is filed. It will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the Action Plan no less frequently than annually. Any refreshed Action Plan will be submitted to the State Commissions for their information. The Action Plan may also be revised as a consequence of subsequent IRPs.

DETAILED ACTION PLAN – FINDINGS OF NEED AND IMPLEMENTATION ACTIONS

The IRP analysis presumes new resources are actual, specific assets. This assumption allows precise modeling of different site, technology and transmission costs. It also creates a realistic framework for a development timeline. In implementing the Plan, however, all resource options will be rigorously compared to alternative purchase options either from the market or from other existing potential electricity suppliers. Additionally, the specifics of any built or purchased asset may be adjusted to optimize based on then current conditions. The potential risks associated with other developers being able to finance independent and merchant power plants will be assessed on a case-by-case basis. The Procurement Program, further discussed below, will assure that new supplies are obtained from the least cost provider. The proposed Procurement Program will enable consistency with Oregon restructuring requirements, as is also discussed below.

PacifiCorp is seeking acknowledgement of the Action Plan by regulatory Commissions in five States. How these Commissions will treat a favorable acknowledgement of an IRP Action Plan in subsequent rate cases may vary.[13] To accommodate potential differences in treatment of an acknowledgement, the detailed Action Plan includes two components. First, Table 9.1 provides specific findings regarding the need for resources. Second, Table 9.2 provides details of the actions arising from this IRP to address the findings of need. The Findings of Need and Implementation Actions are consistent with each other and support the implementation of the Diversified Portfolio I.

Implementation Actions in the first four years of the plan require greater attention and more specificity than those required in the out-years of the plan. Each Implementation Action has

[13] For example, under the Oregon IRP rules, an acknowledged IRP Action Plan is relevant to subsequent ratemaking. When acknowledged, it becomes a working document for use by parties in a rate case or other proceeding. Oregon has suggested the Action Plan be designed to allow Oregon to acknowledge specific findings of fact. See Appendix N for a summary of each State's planning requirements.

been categorized by resource addition type, and includes a target date for the delivery or completion of the action item.

Table 9.1 IRP Action Plan Findings of Need

REFERENCE	FINDINGS OF NEED	IMPLEMENTATION ACTION REFERENCE (See Table 9.2)
1	PacifiCorp needs to procure approximately 500 MW of base load resource in the West of the system by April 2006.	1
2	PacifiCorp needs to procure approximately 570 MW of base load resource in the East of the system by ~~April 2007~~.? ? Summer 2008 Lakeside	2 & 3
3	PacifiCorp needs to procure approximately 500 MW of base load resource in the East of the system by ~~April~~ 2008. Hunter Summer 2008	4
4	PacifiCorp needs to procure 200 MW of peaking resources for the East side of the system for operation in FY ~~2~~006. Summer 2005 CC	15 &16
5	PacifiCorp needs to procure 230 MW of peaking resources for the West side of the system for operation in 2006.	15
6	PacifiCorp needs to prepare, issue and implement RFPs for Renewable resources across the system with a build pattern (based on wind capacity) as follows: • 100 MW – 2006 (West) • 200 MW – 2007 (East) • 200 MW – 2008 (West)	17 - 20
7	PacifiCorp needs to secure shaped products to optimize and fulfill specific shaping needs of the system. Products to be developed are: • The super-peaking needs in the East of the system for 2004/05/06/07 – Duct Firing Capability Currant Creek • The off-peak needs in the West of the system for 2005/06 • Thermal asset based contracts in support of the capacity requirements to achieve 15% planning margin on both the East and West of the system. Appendix F 301	21
8	PacifiCorp needs to develop a more comprehensive portfolio of cost effective Demand Side Management resources with the following targets for the period 2003 to 2014: • Class 1 and Class 3 – 190 MW • Class 2 – 450 MWa	5 -14
9	PacifiCorp needs specific detailed transmission studies to support reference items 1 to 8 above	24 - 27

Table 9.2 Action Plan Implementation Actions for Diversified Portfolio I

ADDITION TYPE		IMPLEMENTATION ACTIONS	TARGET DELIVERY DATE
Base Load - 2007	1.	Procure a base load unit in the West of the system for operation in 2007. Prepare detailed plans including an economic review and justification for building or buying a base load CCCT in the West of the system for 2007. The review will address: • The merits, risks and benefits of negotiating alternative PPA agreements following the expiration of existing contracts in the West • The potential and options for negotiating additional capacity associated with the existing BPA contract (Sites under consideration in the review will include opportunities at Albany, Klamath Falls and others in the West of the system)	July 2003
Base Load - 2008 7/2007	2.	Procure a base load unit in the East of the system for operation in 2008. Summer 2007 [illegible] Coal → Lakeside Prepare detailed plans including a review and justification for building or buying the base load coal unit in the East of the system for 2008. The review will include, but will not be limited to: • An economic review for selecting coal as the fuel • Alternative fuel options including natural gas • Emissions Impacts on the surrounding area • Other existing or partially developed sites • Alternative PPA agreements with appropriate credit worthy counter-parties (Sites under consideration in the review will include opportunities at Hunter, Terminal, Mona, West Valley, Gadsby and others in the East of the system)	October 2003
Base Load - 2008	3.	Continue environmental permitting activity for Hunter 4 to ensure this base load plant option is available for implementation and operation by 2008 in line with DPI requirement (see Action Item 2).	July 2003
Base Load - 2009	4.	Procure a base load unit in the East of the system for operation in 2009. Hunter Summer 2008 Prepare detailed plans including a review and justification for re-powering of the existing Gadsby plant (units 1, 2 and 3) in 2009. The review will include, but will not be limited to: • Alternative existing or partially developed sites	July 2004

ADDITION TYPE	IMPLEMENTATION ACTIONS	TARGET DELIVERY DATE
	• Alternative PPA agreements with appropriate credit worthy counter-parties (Sites under consideration in the review will include opportunities at Terminal, Mona, West Valley and others in the East of the system)	
DSM	5. Design and determine the cost effectiveness of the proposed Air Conditioning Load Control program in Utah. Launch and implement the Air Conditioning Load Control program as appropriate and in line with the findings.	April, 2003
DSM	6. Design and determine the cost effectiveness of the proposed refrigerator re-cycling program. Launch and implement the refrigerator re-cycling program as appropriate and in line with the findings.	April, 2003
DSM	7. Design and determine the cost effectiveness of the proposed efficient central air conditioner program. Launch and implement the efficient central air conditioner program as appropriate and in line with the findings.	April, 2003
DSM	8. Complete an evaluation of the available, realistic CHP sites and market size within the PacifiCorp territory.	April, 2003
DSM	9. Implement and operate the specific DSM programs in the D-P40 decrement that was included DPI. This will build 150 MWa DSM between 2004 and 2014.	Commence July 2003
DSM	10. Conduct an Economic and Market Potential study of the PacifiCorp Service territory to determine the magnitude of the DSM opportunities available to PacifiCorp.	August, 2003
DSM	11. Design a "bundle" of cost effective DSM programs that build to an additional 300 MWa between 2004 and 2014 in line with the decrement options reviewed in the IRP.	July, 2003
DSM	12. Prepare, issue and implement a Request For Proposals (RFP) for 100 MWa of Class 2 DSM for implementation commencing early 2004 as part of the "bundle' of options in action item 11.	April, 2003
DSM	13. Determine revised DSM targets for the period 2004 to 2014 based on the results of action items 10, 11 and 12.	October, 2003
DSM	14. Evaluate and implement as appropriate the irrigation load control program in Idaho for 2004.	May, 2003
Peakers - 2006	15. Procure reserve peaker units for the system for operation in 2006. Develop detailed plans and proposals, including the timeline for delivery, for the reserve peakers required for	July 2003

ADDITION TYPE	IMPLEMENTATION ACTIONS	TARGET DELIVERY DATE
	system 2006: • East side – 200 MW • West side – 230 MW	
Peaking	16. Review the West Valley peaker plant performance and requirement and negotiate the West Valley Peaker plant terms and conditions in line with the existing lease contract arrangements.	July 2004
Renewables	17. Evaluate expansion options for PacifiCorp's Blundell Geothermal plant and implement expansion if appropriate and cost effective.	January 2003
Renewables	18. Prepare, issue and implement an RFP for wind generation on the West of the system in line with the proposed procurement pattern: • 100 MW – 2006 • 200 MW - 2008 • 200 MW - 2010	Issue March 2003
Renewables	19. Prepare, issue and implement an RFP for wind generation on the East of the system in line with the proposed procurement pattern: • 200 MW – 2007 • 200 MW – 2009 • 200 MW - 2011	Issue March 2003
Renewables	20. Prepare, issue and implement an RFP for renewable generation options (i.e. geothermal, solar, fuel cells) which could be implemented in addition to, or as an alternative to, the proposed wind build pattern modeled in DPI (Action Items 18 and 19).	Issue March 2003
Shaped Products	21. Determine the strategy and negotiate, as appropriate, asset based shaped product contracts to fill: • The super-peaking needs in the East of the system for 2004/05/06/07 • The off-peak needs in the West of the system for 2004/05/06 • Thermal asset based contracts in support of the capacity requirements to achieve 15% planning margin on both the East and West of the system. • Thermal asset based contracts (25 MW) to support the addition of profiled wind in the East and West of the system.	Commencing January 2003
Strategy and Policy	22. Determine the long term IRP model(s) including a review of options for using optimization logic for future IRP's	September 2003
Strategy and Policy	23. Agree any changes to Standards and Guidelines that may impact the implementation of the IRP Action Plan	December 2003

ADDITION TYPE	IMPLEMENTATION ACTIONS	TARGET DELIVERY DATE
Strategy and Policy	24. Determine the Planning Margin PacifiCorp will adopt if different from the 15% planning margin adopted in this IRP, following the outcome of the FERC's proposed SMD rule. The analysis for this will include loss of load probability studies.	December 2003
Transmission	25. Detail and commission selected transmission power system analysis studies to support the implementation of the IRP Action Plan for DPI. The studies will provide greater detail on transmission costs associated with all the portfolio additions. Particular attention is required to determine the impact of the potential wind capacity additions on the system from a system stability perspective.	July 2003
Transmission	26. Prepare detailed plans including an economic review and justification and apply for necessary transmission upgrades to support asset additions	July 2003
Transmission	27. Prepare detailed plans including an economic review and justification to implement the "Wasatch Front Triangle" transmission upgrades.	July 2003
Transmission	28. Review options for firming up the IRP non-firm transmission requirement.	July 2003

IRP ACTION PLAN IMPLEMENTATION - DECISION PROCESSES

Chapter 3, Risks and Uncertainties, highlights the need for PacifiCorp to retain the right to adjust its implementation of the IRP in light of the already known, but not clearly defined, paradigm risk implications. The Commissions' IRP rules also point to the need to remain flexible to changes going forward.[14] As discussed above, it is PacifiCorp's intention to revisit and refresh the Action Plan no less frequently than annually. Any refreshed Action Plan will be submitted to the State Commissions for their information. Figures 9.1 to 9.3 provide some insight on the decision processes PacifiCorp will use while implementing the Action Plan. These decision processes will be iterative and occur in conjunction with the Procurement Program discussed below. The alignment of Resource Planning and Business Planning, also discussed herein, will ensure the IRP Action Plan remains current and consistent with ongoing procurement measures.

Figure 9.1 illustrates the process to be followed as the individual resources within DPI are developed and tested in more detail to ensure they are contributing to the low cost, low risk solution in the manner anticipated in the IRP modeling. If there are major changes to the assumptions associated with the portfolio resource selection it is possible that the portfolio may

[14] For example, the Utah Standards and Guidelines call for 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.*

have to be re-designed and the Action Plan reviewed to ensure the desired low cost, low risk option is still being achieved.

Figure 9.1 Decision Process chart for Portfolio Resource Analysis

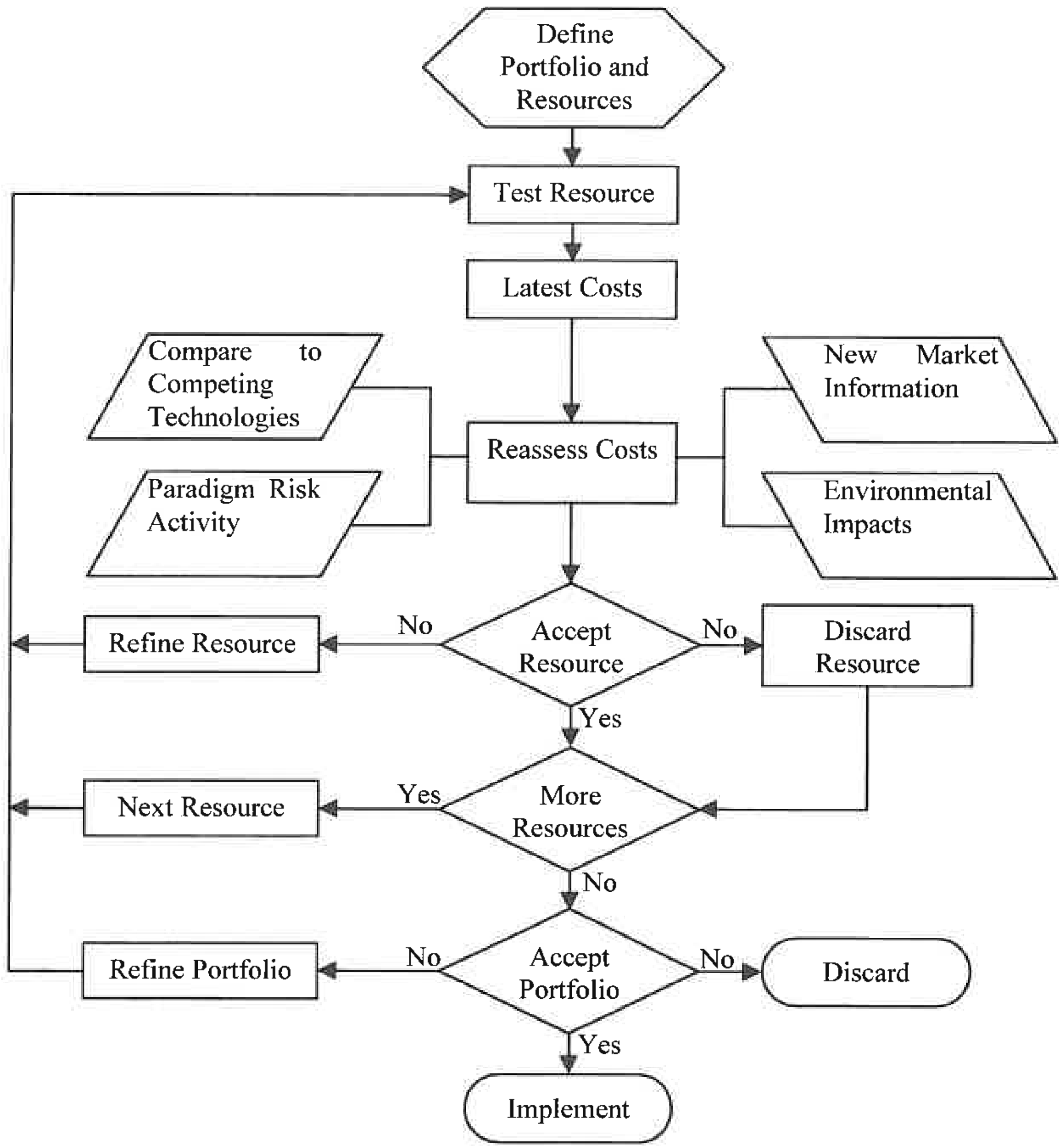
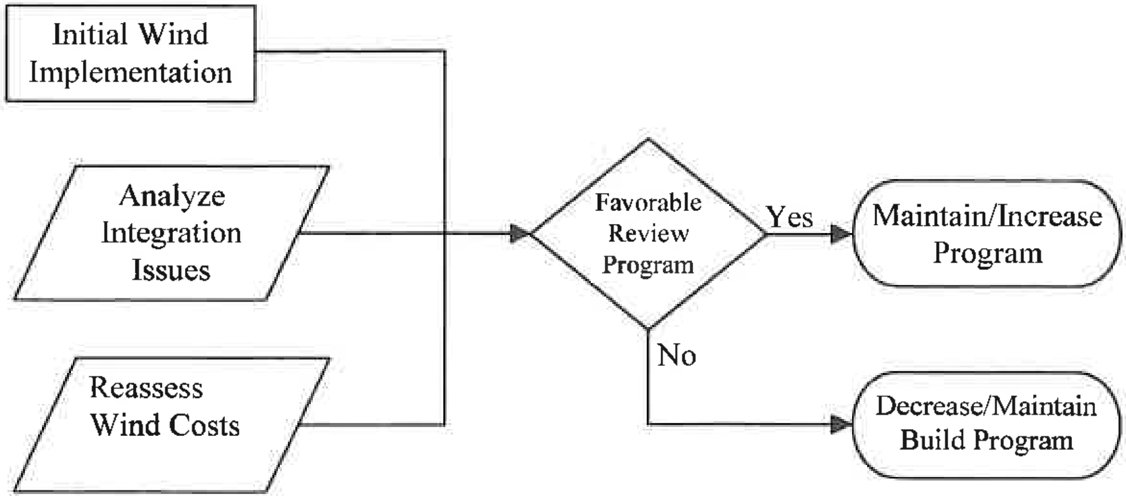


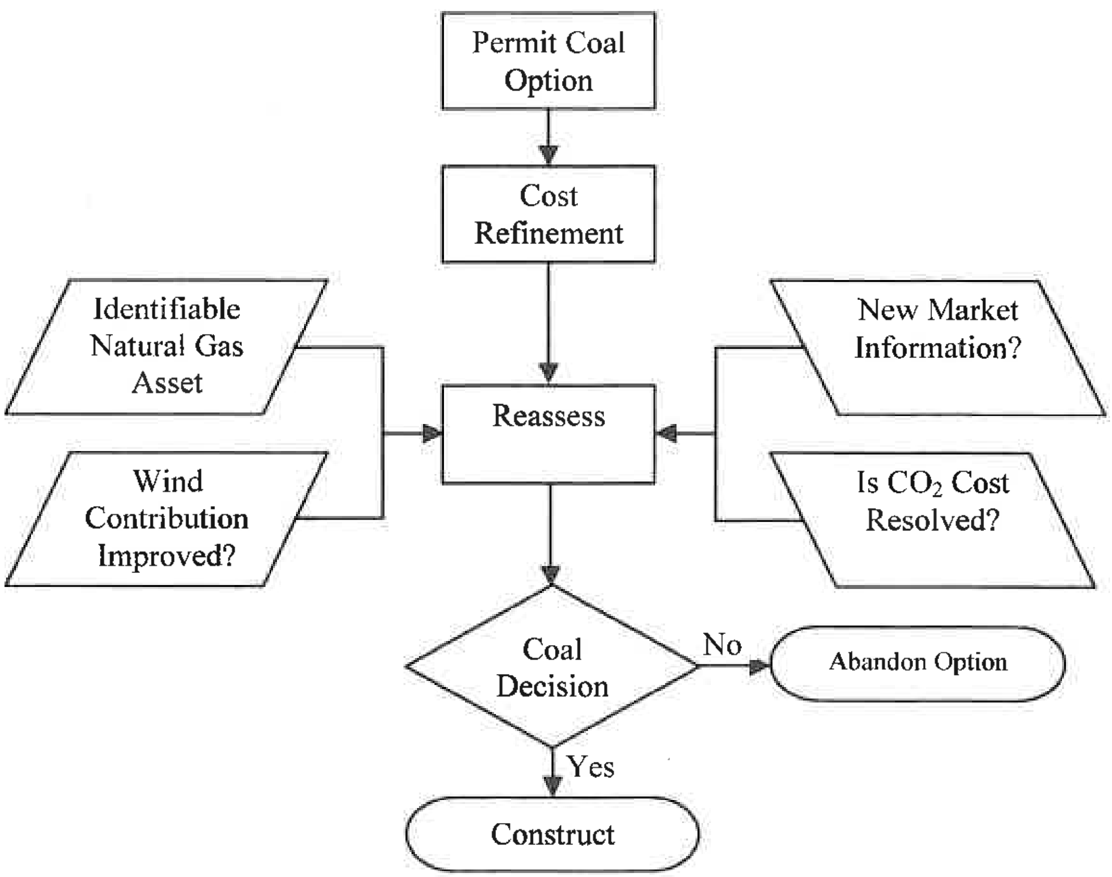
Figure 9.2 addressed the decision process associated with the wind (and other renewables) resources in the Action Plan. The wind build strategy allows time for all parties to develop a greater understanding of the uncertainties associated with wind. The level of wind resource ultimately procured has the potential to become more or less than is reflected in the DPI portfolio. The impact of wind on the portfolio will be tested through the processes illustrated in Figures 9.1 and 9.2.

Figure 9.2 Decision Process Chart for Wind (Renewables) Generation Development



DPI introduces the procurement of a base load coal plant by 2008 (Action Item 2). There are still uncertainties surrounding this technology choice so further clarification will be undertaken. The decision processes shown in Figures 9.1 and 9.3 will be followed to test the assumptions surrounding the current coal proposal.

Figure 9.3 Decision Process Chart for Base Load Technology Choice



IRP ACTION PLAN IMPLEMENTATION - PROCUREMENT PROGRAM

PacifiCorp intends to implement many elements of the Action Plan with a formal and transparent Procurement Program. The IRP has determined the need for resources with considerable specificity, and identified the desirable Portfolio and timing for procurement. The IRP has not identified specific resources to procure, or even determined a preference between asset ownership versus power purchase contracts. These decisions will be made subsequently on a case-by-case basis with an evaluation of competing resource options. These options will be fully developed using a robust procurement process, including, when appropriate, competitive bidding with an effective request for proposal (RFP) process.

DSM programs currently use an outsource model for procurement of results in many of the programs. PacifiCorp intends to continue this practice. In addition, with the substantial increase in results indicated by the 300 MWa planning decrement, procurement of design and implementation of some of this increase in DSM acquisition is anticipated.

The role of RFPs related to a specific resource procurement decision by PacifiCorp will depend upon the size, type, and location of the resource being considered. A comparison of all competing alternatives, including contract purchase options, will be made before PacifiCorp makes a build decision. This comparison will consist of the identification of relevant alternative developers or purchase contract options through a solicitation process, and compared against the appropriate market. In instances where PacifiCorp feels a formal RFP issuance is warranted, due to specific geographic or other market-related conditions, one will be issued.

The evaluation of specific resource alternatives, whether build or contract purchase, will be performed on the same basis and using the same techniques. All evaluations will utilize the best available information known at the time. This means that certain inputs are bound to change during the lead-time associated with any plant construction. As such, the purchase from a plant developer would be subject to a similar level of uncertainty as a PacifiCorp build option, unless the developer imposed a higher level of restriction than PacifiCorp would experience under a build option.

PacifiCorp will perform all evaluations on the same basis and using the same analytical techniques. In general, it is not currently envisioned that evaluations would regularly be done by an independent third party. However, in certain circumstances, such as where an affiliate transaction may be a potential alternative, PacifiCorp may retain an independent consultant to validate that the evaluation is performed on a non-discriminatory basis.

PacifiCorp plans to keep regulators and their staffs apprised of key resource activities, including progress on the Procurement Program. We anticipate providing Procurement Program status reports approximately every six months. The feedback we receive will be taken into account with respect to the particular resource procurement effort. Given the fact that PacifiCorp operates in multiple states, it is not currently envisioned that every state will directly participate in the preparation of a formal RFP issuance.

Due to competitive confidentiality concerns, and potential conflict of interest, it is also not envisioned that third parties would directly participate in the preparation of a formal RFP.

CURRENT PROCUREMENT AND HEDGING STRATEGY

Prior to the implementation of the IRP Action Plan, PacifiCorp will continue with its current procurement and hedging strategy to ensure a low cost, safe and reliable supply for the customer. This effort includes an extension of the September 2001 RFP activities, cost effective demand-side management programs, construction of the Gadsby peakers (now fully operational), temperature contingent hedges, summer procurement 2002-2004, superpeak purchases 2003-2005, and other portfolio optimization opportunities.

The summer season procurement strategy has integrated both financial and physical hedging instruments to strategically manage the physical system, which requires more than purchasing over the counter (OTC) standard on-peak product (6X16). The 6X16 product available from the OTC market is available in blocks, which creates two problems, the need to cover superpeak demand and the requirement to sell surplus shoulder hour power, potentially at a loss, back to the market. The overall objective is to minimize PacifiCorp's risk and deliver the most economic solutions for both the customers and PacifiCorp.

To date, the September 2001 RFP and subsequent extension has resulted in the following major transactions:

- 200 MW of daily call options June - September 2002-2004,
- 15-year lease with early termination rights on 200 MW at West Valley,
- June - September 2002 Temperature Hedges
- 200 MW of superpeak power 2003 - 2005
- An RFP for a May – September 2003 Quanto Temperature Hedge has been issued.

The IRP will be the road map to address resource requirements beyond 2005. Products similar to those detailed above will continue to be developed in line with the IRP Action Plan as they are critical for shaping, optimizing and minimizing the costs and risks associated with the efficient operation of the network.

ALIGNMENT OF RESOURCE PLANNING AND BUSINESS PLANNING

PacifiCorp has made significant improvements to its resource planning organization and methods. These measures have strengthened the alignment of PacifiCorp's business planning, regulatory requirements, resource planning, resource procurement and system operations. A Resource Planning function was created and organized in the Commercial and Trading department to ensure integration with PacifiCorp's resource procurement, trading and risk management functions. New models were developed to ensure the IRP uses a robust analytical framework to simulate the integration of new resource alternatives with PacifiCorp's existing generation and transmission assets, to compare their economic and operational performance. The methodology also accounts for the uncertain future by testing resource alternatives against measurable future risks and possible paradigm shifts in the industry. The modeling and methodology will continue to be developed to address the paradigm shifts as they unfold.

CONSISTENCY WITH OREGON RESTRUCTURING

The Oregon Restructuring legislation (SB-1149) states that *electric companies must include new generating resources in revenue requirement at market prices, and not at cost.*[15] The Oregon PUC has not resolved how this provision would be implemented or if it should be modified, and recently decided to open an investigation into the matter.[16] As noted elsewhere in the report, the IRP has not identified specific resources to procure, or even determined a preference between asset ownership versus power purchase contracts. These decisions will be made subsequently, on a case-by-case basis, as part of the Procurement Program. Thus, the IRP Action Plan is consistent with SB1149 and does not address the ratemaking treatment of new resources. Subsequent procurement of any generating resources will be made consistent with anticipated ratemaking requirements, including SB1149 as implemented by the Oregon PUC.

[15] OAR 860-038-0080(1)(b).
[16] OPUC Order No. 02-702 at 3.

APPENDIX A – ELECTRIC UTILITY BACKGROUND

FEDERAL ACTIVITY

Federal Power Act Of 1935

The Federal Power Act (FPA) of 1935 established the guidelines for federal regulation of public utilities engaging in interstate commerce of electricity. Through this act, the Federal Power Commission (FPC) was given wider authority, including the ability to:

- Issue licenses for new hydrogeneration projects,
- Collect utility operational and financial data, including original investment costs and electric generation and sales data, and
- Review electric rates charged by utilities and establish their depreciation schedules.

One of the most important implications of the FPA was the requirement for utilities to charge "fair and reasonable rates." By forcing utilities to publish all rate schedules for public and government review, the FPA required utilities to defend all rates on a cost of service basis. Charging different rates to customers became illegal, absent substantial cost justification. Further, the FPA established the allowable time frame for utilities to change rate schedules.

The FPA of 1935 also outlined strict conflict of interest rules for officers and directors of public utilities engaging in interstate commerce. The FPC was terminated in 1950 when its powers were transferred to the Federal Energy Regulatory Commission. Later, the United States Department of Energy assumed some of FERC's powers.

Holding Company Act of 1935

Also passed in 1935 was the Public Utilities Holding Company Act (PUHCA). Designed to work in tandem with the FPA of 1935, PUHCA sounded the death knell for multi-tiered holding company structures (described below) that had prevented effective regulation of public utilities, and put utilities operating in more than one state under heavy regulation by the Securities Exchange Commission (SEC). As a result of PUHCA, most utilities operate within a single state (or in multiple states with a contiguous service territory), which allows them exemption from much of the oversight applied by the SEC.

Prior to this legislation, the United States electricity industry had experienced significant consolidation, to the extent that only three companies controlled 45% of the United States electricity market. While many states had public utility commissions, none of these agencies had significant regulatory power, especially when pitted against companies involved in commerce across state lines. Because of the lack of regulatory oversight, holding companies buffered themselves from government regulation by separating from their operating subsidiaries through multiple layers of holding companies, aligned through intentionally complex affiliate relationships. The result was that a few holding companies enjoyed substantial market power and could not be held accountable for engaging in collusive pricing strategies. For example, parent holding companies often charged exorbitant construction rates to their electric companies, which in turn passed on the expenses to consumers. The Federal Trade Commission issued a report in 1928 that listed the abusive practices of holding companies. It concluded that the holding company structure was unsound and "frequently a menace to the investor or the consumer or both."

Further, by being able to hide debt through the multiple levels of holding companies, utilities were able to carry extremely high debt ratios that eventually caused their demise after the stock market crash of 1929. Unable to service their debt, 53 holding companies with combined securities of $1.7 billion went into bankruptcy.

PUHCA and the FPA of 1935 were a direct result of negotiations between utility holding companies and the federal government that began after publication of the Federal Trade Commission's report. Utility owners agreed to provide reliable service at a regulated rate in exchange for an exclusive service territory. Rate regulation would be the responsibility of the Federal Power Commission as established under the FPA of 1935, while the majority of inter-company financial transactions would be regulated by the SEC as outlined in PUHCA. Also, PUHCA dismantled the multi-tiered holding company structure by making it illegal to be more than twice removed from operating subsidiaries.

As a result of PUHCA, more than a third of holding companies owning electricity and natural gas distribution utilities were forced by the SEC to divest such that their electricity and gas services were no longer affiliated. Sections 3(a)(1) and 3(a)(2) allow exemption from PUHCA if the holding companies operate in a single state or within contiguous states. While most holding companies chose to operate so as to qualify for PUHCA exemption, state public utility or public service commissions still strictly regulate these firms.

PURPA – 1978

The Public Utilities Regulatory Policy Act is one of five bills signed into law on November 9, 1978, as part of the National Energy Act. It is the only one remaining in force. Enacted to combat the "energy crisis," and the perceived shortage of petroleum and natural gas, PURPA requires utilities to buy electricity from non-utility generating facilities that use renewable energy sources or "cogenerate," i.e., use steam both for heat and to generate electricity. A non-utility generating facility that meets certain ownership, operating and efficiency criteria established by the FERC is known as a Qualifying Facility or QF. The Act stipulates that electric utilities must interconnect with QFs and buy the capacity and energy they offer at the utility's avoided cost.

One of the other bills passed in 1978 was the Fuel Use Act. On the understanding that the United States was soon to run out of natural gas reserves, Congress passed a law that severely limited the amount of natural gas that could be used to generate electricity. Those limitations were removed in the 1980s and natural gas is currently the fuel of choice for new generation in the United States.

Energy Policy Act Of 1992

The Energy Policy Act of 1992 (EPACT) opened access to transmission networks and exempted certain non-utilities from the restrictions of the Public Utility Holding Company Act of 1935 (PUHCA). EPACT made it easier for non-utility generators to enter the wholesale market for electricity. While EPACT opened access to transmission networks for purposes of wholesale transactions, the act did not mandate open access for retail load. The act left it up to individual states to determine if they wanted to open access to electricity lines for purposes of retail sales.

The act also created a new category of electricity producers called exempt wholesale generators (EWGs). By exempting them from PUHCA regulation, the law eliminated a major barrier for utility-affiliated and nonaffiliated electricity producers wanting to compete to build new non-rate-based electricity plants. EWGs differ from PURPA QFs in two ways. First, they are not required to meet PURPA's utility ownership, cogeneration or renewable fuels limitations. Second, utilities are not required to purchase electricity from EWGs.

In addition to giving EWGs and QFs access to distant wholesale markets, EPACT provides transmission-dependent utilities the ability to shop for wholesale electricity supplies, thus releasing them—mostly municipals and rural cooperatives—from their dependency on surrounding investor-owned utilities for wholesale electricity requirements. The transmission provisions of EPACT have led to a nationwide open-access electricity transmission grid for wholesale transactions.

FERC Order 888 – 1996

With the passage of EPACT, Congress opened the door to wholesale competition in the electric utility industry by authorizing FERC to establish regulations providing open access to the nation's transmission system. FERC's subsequent rules, issued in April 1996 as Order 888, are designed to increase wholesale competition in the nation's transmission system, remedy undue discrimination in transmission and establish standards for stranded cost recovery. A companion ruling, Order 889, requires utilities to establish electronic systems to share information on a non-discriminatory basis about available transmission capacity.

FERC Order 2000 – 1999

In an effort to continue the evolution of competitive wholesale electricity markets, FERC Order 2000, released in December 1999, requested the voluntary formation of regional transmission organizations (RTOs). FERC's review of electricity markets had shown evidence that traditional management of the transmission grid by vertically integrated electric utilities was inadequate to support the efficient and reliable operation necessary to the evolution of competitive markets. FERC concluded that RTOs, organizations designed to operate and control regional transmission systems, would be the best way to proceed to protect the public interest and ensure consumers pay the lowest possible price for reliable service.

FERC's voluntary plan is for all transmission-owning entities in the United States to place their transmission facilities under the control of RTOs that will manage operational and reliability issues and eliminate residual discrimination in transmission service.

The fundamental goals, as expressed by FERC in Order 2000, are to:

- Improve efficiencies in transmission grid management,
- Improve grid reliability,

- Remove remaining opportunities for discriminatory practices,
- Improve market performance, and
- Facilitate lighter handed regulation.

To achieve this end, the rule established minimum characteristics and functions for RTOs, a collaborative process for owners and operators of interstate transmission facilities to consider and develop RTOs, a rate-making reform process, and a schedule for public utilities to file with FERC to initiate RTO operations.

Order 2000 is designed to create more efficient transmission systems across the United States to support the growing number of regional wholesale electricity markets. By reconfiguring the existing patchwork transmission system into consolidated transmission organizations, FERC's goal is to spur interest in the investment and construction of transmission assets. Order 2000 also seeks to lower both economic and trade impediments among transmission organizations on a regional basis. Order 2000 reflected the FERC's desire that RTOs to be voluntary in formation and its intent to accept a variety of possible RTO structures.

FERC SMD NOPR - 2002

Continuing to refine its views on transmission in relation to competitive electricity markets, the FERC issued a Notice of Proposed Rulemaking on Standard Market Design (SMD) and Structure, NOPR RM01-12-000. Comments on proposed rules implementing the FERC's vision of standard market design are being taken through December 2002, with final regulations expected in 2003. The SMD proposes a number of remedies aimed at removing barriers to efficient competitive wholesale markets perceived by FERC in the wake of Orders 888 and 2000. The SMD NOPR proposes a new entity called an independent transmission provider (ITP) and would require all FERC jurisdictional utilities to form an ITP, transfer operation of its transmission assets to an RTO that meets requirements of an ITP or contract with an ITP to operate its transmission facilities. Among the functions required of an ITP are:

1. The operation of day-ahead and real-time markets;
2. Filing and administration of a single network access tariff for transmission services and ancillary services;
3. Establishing a market monitoring function with procedures to mitigate market power; and
4. Conducting a planning process with market participants to ensure resource adequacy.

As part of the planning process requirements of SMD, the NOPR proposes to establish a resource adequacy requirement on all utilities using ITP transmission and markets. The proposed rules leave the final word definition of resource adequacy to the ITPs and state and regional advisory boards, but suggest that resource adequacy might require a utility to demonstrate a reserve margin of 12% or more for three or more years with specific, assured assets. Remedies in the form of a penalty charge on market purchases could be imposed on utilities that do not demonstrate resource adequacy.

BRIEF REVIEW OF NATIONAL ACTIVITY REGARDING RETAIL DEREGULATION

Federal legislation has focused on implementation of competition in wholesale electricity markets, while details about retail direct access have been left to the individual states. The restructuring legislation and regulations of the 1990s, particularly the EPACT, have brought about retail-level industry restructuring in several states. The national movement towards a restructured electric utility industry has proceeded at varying paces in different geographic regions. The map below summarizes the status of state electric restructuring activities as described on the United States Department of Energy – Energy Information Administration web site (http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html).

Figure A.1 Retail Restructuring

State level restructuring has several common elements: the establishment of retail customer choice, a method to allow regulated vertically integrated utilities to be compensated for investments made in existing generation which may not be recoverable in competitive markets (known as "stranded costs"), and the functional separation of the regulated utilities into separate generation, transmission, distribution and retail service provider business units. There are many differences in the approach to retail restructuring.

California Experience

The California experience is singled out in this report because it has proven to be a case study on how not to approach the transition from regulated bundled electric service to unbundled retail competition. The legislation that introduced electricity industry restructuring in California was Assembly Bill 1890. AB 1890 promised to achieve a number of goals for California energy consumers, including lower electricity bills and choice of generation providers. A key to realizing these goals was a continued adequate supply of electricity. Unfortunately, the Western U.S. ran into a severe shortage of electricity before California completed the transition to its fully deregulated state. This caused disastrous problems for California and the WECC, as described in Chapter 2. Some of the key aspects that created these problems were:

- Lack of new resources
- Large quantity of spot market power exposure by California's private utilities
- Retail rates frozen for California's private utilities
- Deregulated wholesale electricity prices
- Severe drought in WECC resulting in reduced hydrogeneration

In September of 2001, after wholesale prices had retreated and stabilized, the California PUC suspended retail choice. The CPUC estimates that about 2,300 MW of the state's peak load of 46,000 MW is currently under direct access contracts, mostly with large industrial customers. Contracts in place were allowed to continue until their expiration.

Other State Activity

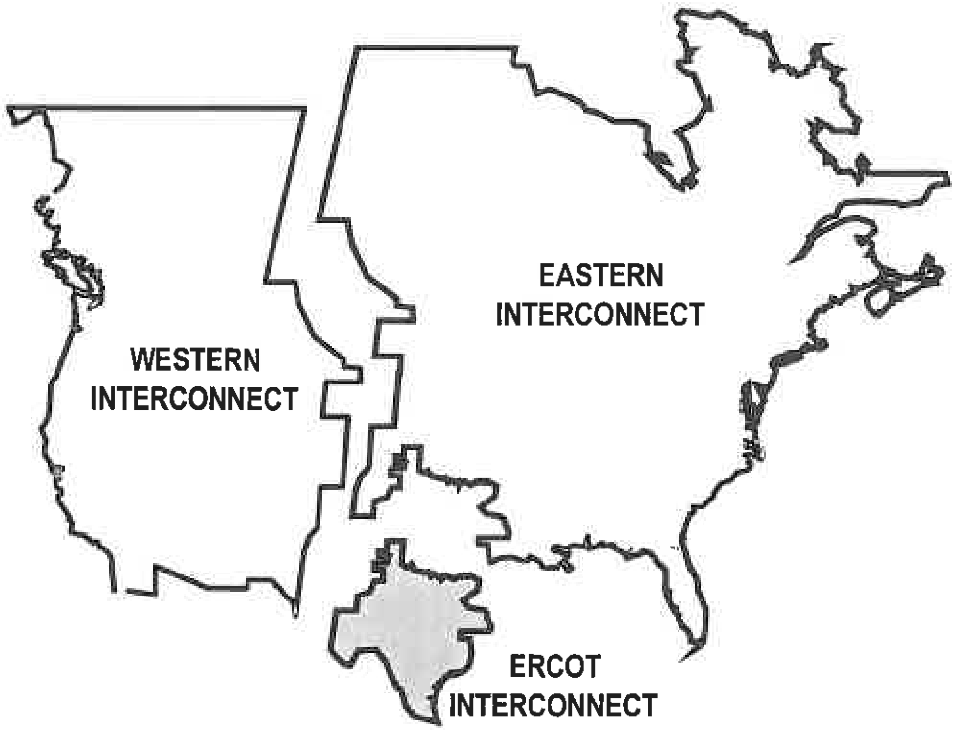
The problems experienced in California are causing other states to slow retail direct access in order to re-examine at their retail level restructuring plans in hope of avoiding similar outcomes. According to the EIA, six states have suspended or delayed restructuring activities and about half the 50 states are not actively undertaking restructuring at this time.

OVERVIEW OF WESTERN ELECTRICITY MARKETS

The Western Interconnect

The Western Interconnect is one of three interconnected grids in North America separated from each other by limited capacity direct current interties (see Figure A.2).

Figure A.2 Transmission System Interconnections for the United States and Canada



The nature of this interconnection provides for robust wholesale electricity market transactions among the utilities (such as PacifiCorp) that make up the interconnected grid. These electricity transactions are a mixture of long-term contracts, seasonal contracts, day-ahead (spot) transactions, and "real-time" transactions. In addition, a number of financial transactions are offered within the Western Interconnect, such as swaps under which a buyer exchanges volatile spot market prices for fixed prices.

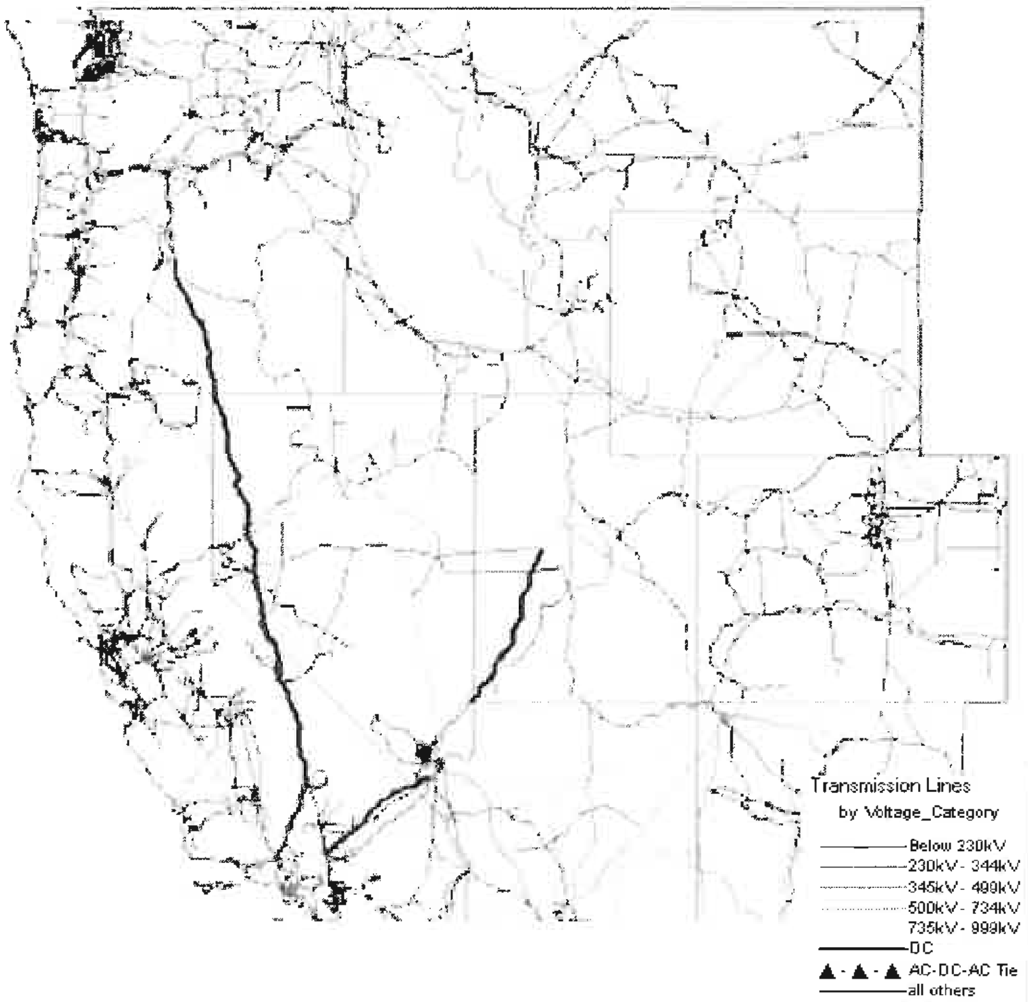
The Western Electricity Coordinating Council (WECC), organized in August 1967, provides coordination in operating and planning a reliable and adequate electricity system for the Western Interconnect. The WECC is the largest, geographically, of the regional councils of the North American Electric Reliability Council (NERC). It covers most of 11 western states, two Canadian provinces, and a small part of Northwestern Mexico. The acronym WECC is often used to refer to the Western Interconnect, and not the organization, and is frequently meant to designate the United States portion.

Electric Transmission in WECC

The WECC interconnection is made up of a vast high voltage transmission grid that allows movement of electricity in a flexible manner. While there is good ability to move electricity to and from many areas of WECC, at times there may be the desire to move more electricity than the transmission grid can handle. Path ratings and electricity flows are provided by the WECC to avoid such congestion, while a plethora of contractual arrangements govern who has the right to use the capability of the transmission system.

Figure A.3 shows the major transmission lines that make up the WECC interconnected grid.

Figure A.3 Major Transmission lines in WECC



The Load/Resource Balance In WECC

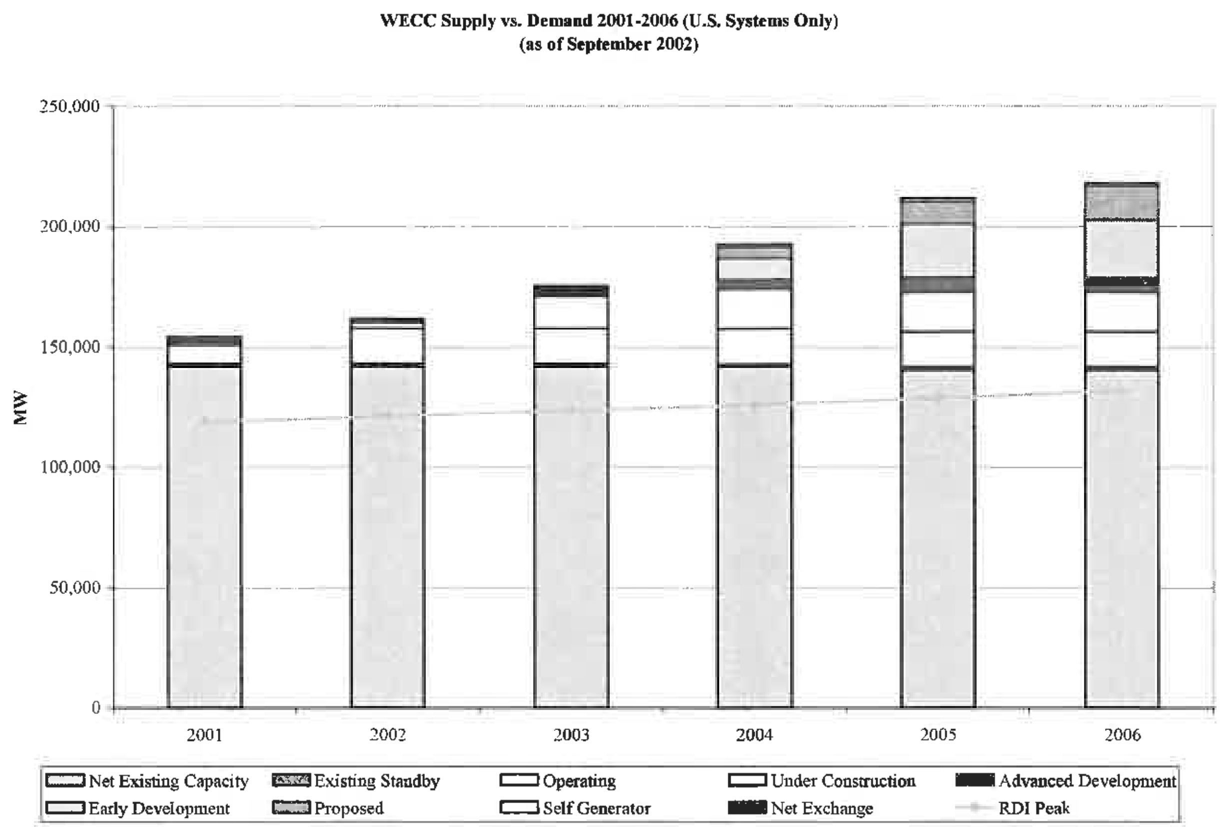
The actual peak load in WECC in the summer of 2000 was 130,892 MW and 125,040 MW in the summer of 2001. Peak load in the summer of 2001 was significantly reduced as a result of demand response to the recent electricity crisis in WECC and slowdown in economic activity attendant to the ongoing recession.

There is approximately 166,000 MW of generation capacity in WECC. About 62,000 MW of this total is hydrogeneration. Total hydrogeneration capacity cannot be fully relied upon for meeting peak loads across all heavy load hours because of limited reservoir storage.

The WECC load/resource balance is currently undergoing rapid change with a wave of new generation. Additions totaling 14,800 MW reached commercial operation in 2001 and 2002 (through September 2002). An additional 16,700 MW is under construction with commercial operation expected by 2004. California and Arizona lead other states in these capacity additions by a wide margin, especially in the 2001-02 cohort groups. Looking specifically at projects under construction by state, California and Arizona, have under construction 5,700 MW and 5,600 MW, respectively, expected between September 2002 and year-end 2004. Nevada also stands out, at 3,150 MW under construction, 75% of that expected in 2003. Capacity under construction is overwhelmingly combined cycle – 14,000 MW of 16,700 total. The combined cycle and combined cycle/cogeneration capacity categories also dominate generation put into service since January 2001, at 8,400 MW out of 14,800 MW. Simple cycle CTs also make a major contribution, with 4,800 MW added last year and this.

Despite the suspension of construction during 2002 on more than 1,500 MW of capacity already under construction, it appears that WECC reserve margins are recovering from the margins that contributed to the 2000-2001 electricity crisis. Figure A.4 illustrates existing and new generation in relation to projected peak demand for the United States portions of the WECC.

Figure A.4 WECC Existing and New Generation versus Demand

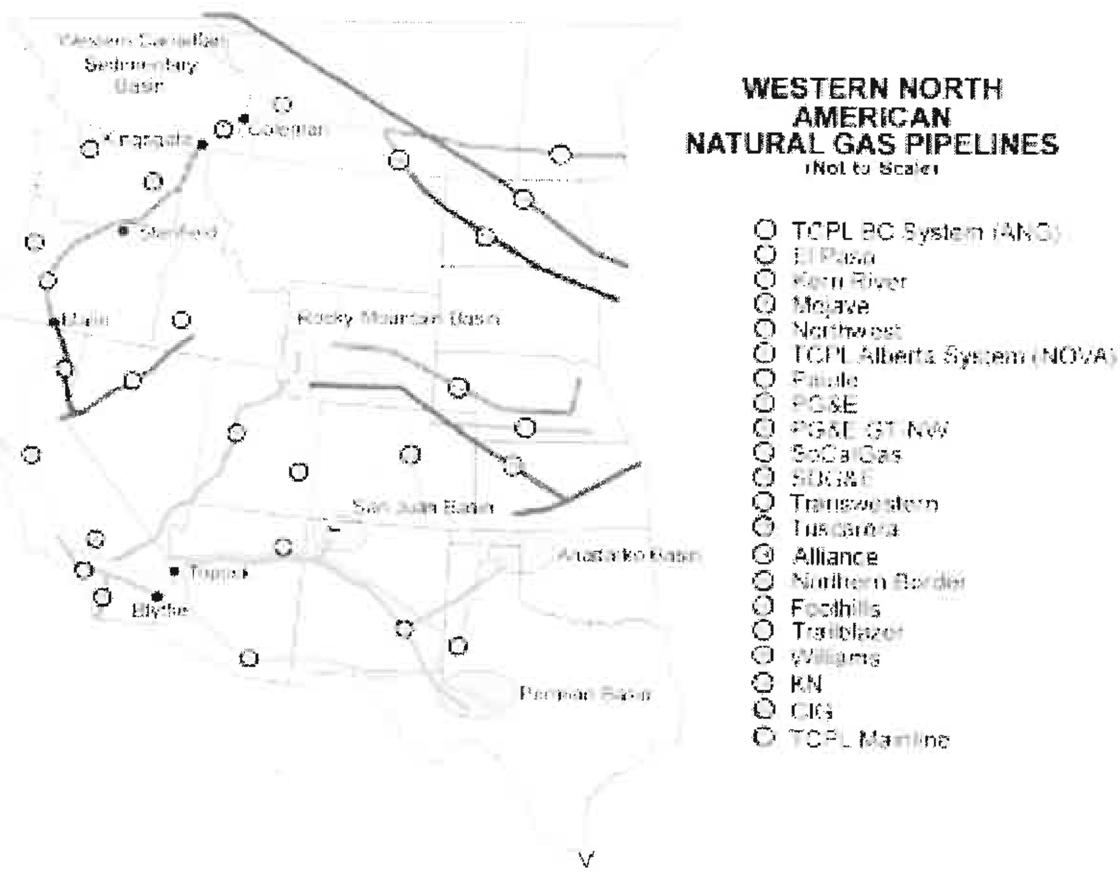


Natural Gas Overview In WECC

Natural gas plays a very important part in electricity markets in the WECC since natural gas-fired resources are on the margin for nearly all hours of the year. Natural gas reserves in North America appear to be plentiful. Much of the most economical new reserves, however, are in frontier areas. In particular, large exploitable reserves are expected from arctic North Slope resources in Alaska and the Mackenzie Delta of Canada. The major challenge in development of these resources for North American supplies is construction of one or more pipelines to Western Canada and the United States None of the several competing arctic gas pipelines is expected to be constructed before 2008. In the interim, liquefied natural gas (LNG) imports are expected to meet much of the net gas demand growth over the next six years.

Natural gas pipelines are relatively easy to permit and build in the relatively unpopulated areas of WECC. A large number of pipeline expansions or new pipelines are being proposed in WECC. Figure A.5 shows the major gas supply basins and gas pipelines in WECC.

Figure A.5 Major Gas pipelines and Supply Basins



<u>Coal Overview for WECC</u>

Prior to May 2000, nearly all new electricity plants being proposed for WECC were fueled by natural gas. The very high natural gas prices that occurred in the May 2000 to June 2001 time period have resulted in renewed interest in coal-fired generation.

There are very large coal reserves in Western North America. While coal-fired generation has higher capital cost and longer lead-time for construction, coal fuel operating costs can be much lower than the operating cost of a natural gas generator. This is especially true if the coal plant can be built near the coal reserve, thus avoiding the need to transport the coal great distances. Further, coal costs are historically less volatile than natural gas costs.

Since coal reserves are not located close to large metropolitan areas (i.e., where the large blocks of retail load are located), it becomes necessary to carefully assess the capability of the transmission grid to move the electricity from a new coal-fired generating plant to the load it will be serving.

OVERVIEW OF THE PACIFIC NORTHWEST AREA OF THE WECC

The Pacific Northwest (PNW) is a subset of the WECC. WECC defines the PNW in two different fashions. The larger PNW includes British Columbia and Alberta, Canada. The United States portion of the PNW excludes them. The Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501, December 5, 1980) defines the Pacific Northwest as the area consisting of Oregon, Washington and Idaho; the portion of Montana west of the Continental Divide; the portions of Nevada, Utah and Wyoming that are within the Columbia River drainage basin; and any contiguous areas not in excess of 75 air miles from the area referred to above that are a part of the service area of a rural electric cooperative customer served by the BPA administrator on December 5, 1980, that has a distribution system from which it serves both within and without such region.

Under this definition, only the PacifiCorp service territory in Utah and parts of Wyoming are not located within the PNW.

The Bonneville Power Administration

The Bonneville Project Act (P.L. 75-32, August 20, 1937) was passed to establish the Bonneville Power Administration (BPA) as the entity responsible for delivery and marketing the electricity from federally owned dams in the PNW. Currently, BPA markets the electricity from 30 hydrogeneration projects and one nuclear plant. BPA has also built a massive electricity grid in the PNW. BPA's transmission system accounts for about three-quarters of the region's high-voltage grid and includes major transmission links with other regions. As such, PacifiCorp utilizes the BPA transmission system under numerous commercial arrangements (and BPA similarly utilizes PacifiCorp's transmission system).

The Northwest Power Act of 1980

The Pacific Northwest Electric Power Planning and Conservation Act (Act) was passed by Congress in 1980 primarily to resolve debates and litigation in the region regarding who would have access to the Federal Base System (FBS) electricity (primarily federally owned hydrogeneration facilities) whose output is marketed by the BPA. The Act prescribed the formation of the Northwest Power Planning Council that has eight council members. The members include two governor appointees each from Oregon, Washington, Idaho and Montana. The Act provides for the development of both an electricity plan and a fish and wildlife program for the PNW. Importantly for PacifiCorp, the Act provided for a "Residential Exchange" under which PacifiCorp gets access to FBS electricity for its residential load in the PNW. This access may be in the form of an exchange of higher cost PacifiCorp electricity for lower cost FBS electricity or as a direct sale of FBS electricity. Resulting economic benefits are passed directly to eligible residential customers served by PacifiCorp.

Endangered Species Act Effect on Electricity Supply

The Endangered Species Act (ESA) was passed by congress in 1973. ESA has had a profound impact on electricity supply in the Pacific Northwest primarily through its impact on the operation of hydrogeneration electricity plants. Declining stocks of various species of fish (including several salmon species) have led to an effort to alter hydrogeneration project operations to protect them. Many of the hydrogeneration projects in the PNW (including those owned by PacifiCorp) require a FERC-approved license to operate. Either during the re-licensing of these hydrogeneration projects or via an opening up of an existing license, FERC can require extensive modifications to the physical facilities or operation of the facilities that greatly reduces the electricity value of the project. Many PacifiCorp-owned hydrogeneration projects are facing these issues.

Federally owned hydrogeneration projects are not licensed by FERC, but are still subject to the ESA in their design and operation. As a result of listing a number of endangered or threatened species of fish, the National Marine Fisheries Service (NMFS) prepares a biological opinion of whether the operation of the Federal Columbia River Power System (FCRPS) jeopardizes the species and, if so, how the operation of the FCRPS must be altered in order to avoid jeopardy. These NMFS biological opinions have had a significant impact on storage and release of water at the many federal dams in the PNW and on the use of the water (e.g. requirements to spill water rather than running the water through turbines to create electricity). These impacts on the FCRPS impact prices that BPA must charge PacifiCorp for certain electricity purchases, the availability of electricity in WECC, and prices that PacifiCorp will experience in its spot market purchases and sales.

DIRECT ACCESS INITIATIVES IN STATES WHERE PACIFICORP SERVES

Oregon

Oregon has enacted legislation (SB 1149 and HB 3633) to initiate retail choice for all customers, except residential, by March 1, 2002. The Public Utility Commission (OPUC) is to report by January 1, 2003, on whether direct access will benefit residential customers. Starting March 1, 2002, residential customers will be able to purchase electricity from a portfolio of rate options.

The OPUC adopted a number of rules (in AR 380) to implement provisions of SB 1149. One key rule is that an electric company may retain only those resources that will be needed to serve its Oregon residential and small nonresidential customers. To aid in the accomplishment of this policy, the rules require each electric company to produce a resource plan stating whether a generating resource should be retained to serve residential and small nonresidential consumers and thus administratively values; sold through the auction process; or removed from the company's Oregon revenue requirement and administratively valued. The administrative rules that address resource plans are expected to be resolved in 2003.

The deregulation rules in Oregon also address a number of other aspects of initiating direct access in Oregon. The other matters addressed include, but are not limited to, potential market power, stranded cost recovery and public benefits funding.

APPENDIX B – PUBLIC INPUT PROCESS

A critical element of this planning process has been the public input process. PacifiCorp has pursued an open and collaborative approach to involve the Commissions, customers and other stakeholders in PacifiCorp's planning prior to PacifiCorp making resource decisions. Since these decisions can have significant economic and environmental consequences, conducting the resource plan with transparency and full participation from the Commission and other interested and effected parties is essential.

The public has been involved in this resource plan from its earliest stages and at each decisive step. Participants have both shared comments and ideas and have received information. As reflected in the report, many of the comments provided by the participants have been adopted by PacifiCorp and have helped contribute to the quality of this resource plan. PacifiCorp will adopt further comments going forward, either as elements of the action plan or in future refinement to the planning methodology.

The cornerstone of the public input process has been full-day public input meetings, held approximately every six weeks throughout the year-long plan development period. These meetings have been held jointly in two locations, Salt Lake City and Portland, using telephone and video conferencing technology, to encourage wide participation while minimizing travel burdens and respecting everyone's busy schedules.

The public input meetings were augmented by a series of focused workshops on specific topics, as the need often arose for further detailed discussion among the participants. In addition, questions or comments frequently arose in these meetings that required further consideration or research by PacifiCorp. PacifiCorp addressed these issues, sometimes referred to as the *parking lot*, with written clarification.

As a further means for ensuring the public participants would be informed by data used in the planning which is commercially sensitive, PacifiCorp utilized confidentiality agreements and protective orders to facilitate this involvement, while protecting customers from potentially negative consequences associated with making this data generally available.

This Appendix provides a summary of who participated; when the public input meetings occurred and what was discussed; a summary of the public technical workshops and parking lot issues. A summary of the comments we received on the draft report, with PacifiCorp's response and disposition is provided in Appendix O.

<u>Public Input Participants</u>

Among the organizations that were represented and actively involved in this collaborative effort were:

- Citizen's Utility Board of Oregon
- Committee for Consumer Services State of Utah
- Crossroads Urban Center
- Idaho Public Utilities Commission

- Industrial Customers of Northwest Utilities
- Land & Water Fund of the Rockies
- Large Users Energy Company
- Northwest Energy Efficiency Alliance
- Oregon Department of Energy
- Oregon Public Utilities Commission
- Public Service Commission of Utah
- RES North America
- Renewables Northwest Project
- Salt Lake Community Action Program
- Tellus Institute
- Utah Association of Energy Users
- Utah Clean Energy Alliance
- Utah Division of Public Utilities
- Utah Energy Office
- Utah Legislative Watch
- Utah Wind Power Campaign
- Wasatch Clean Air Coalition
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

PacifiCorp extends its gratitude for the time and energy these participants have given to the plan. Your participation has contributed significantly to the quality of this plan, and your continued participation will help as PacifiCorp strives to improve its planning efforts going forward.

Public Input Meetings

PacifiCorp hosted nine full-day public input meetings to discuss various issues including inputs & assumptions, risks, modeling techniques and analytical results. A tenth and final meeting of this IRP cycle will be scheduled in February 2003, to provide parties an opportunity to clarify the final IRP that has been filed. A brief summary of the topics discussed at each meeting is provided here.

December 13, 2001

Acknowledgements of RAMPP 6
Resource Planning Environment
Desired Results from Resource Planning
Role of Resource Planning
Components of the IRP
Critical Path and timing
Next Steps

February 5, 2002

- Goals
  - IRP
  - Meeting

- Model Criteria & Current Models
  - Desired Model Criteria
  - Key Considerations for 2002 Model Decision
  - Current 2002 Resource Planning Models
  - Expectations of Modeling Criteria and Current Models
  - Comparison of Current Models
  - MultiSym – What It Will and Won't Do?
  - Where Are We Now?
- Long Term Model(s)
  - Desired Outcomes from Discussion
  - Model Criteria – Is Anything Missing?
  - Matrix of Models Being Evaluated
- Future Meetings

March 22, 2002
- High Level Timeline for IRP
- Inputs and Assumptions
  - System Topology
  - Load Forecasts
  - Market Price Forecasts
  - Existing Resource Stack
  - New Resource Options
  - Environment
- Risk Analysis
  - Risk vs. Uncertainty Discussion
  - Current Methodology for Analyzing and Comparing Portfolios
- Next Steps/Future Agendas

May 7, 2002
- Process Check – Part 1
- Modeling Discussion
  - Discussion on CCS Memo
  - Modeling Update
- Risk Analysis
  - Risk Modeling Update: Process, flow of information
  - Scenarios/Stresses: Overview of Scenarios, Overview of Stresses
- Process Check – Part 2
- Next Meeting

June 18, 2002
- Confidentiality Agreements
- Load/Resource Balances
- Overview of Technical Workshops
- Planning Horizon & Action Plan

- Portfolio Selection Process
  - Resource Characteristics
  - Size and Timing
  - Selecting Portfolio Combinations
- Next Steps

July 30, 2002
- Update on "Parking Lot" Issues
- IRP Environmental Issues
- Update on Risk Model
- Update on Portfolio Selection Process
- Preliminary Results of Portfolio Runs
- Next Steps

September 24, 2002
- Updates since July 30 Meeting
- Results of Portfolio Runs
  - Overview of New Portfolios
  - DSM
  - Risk Analysis – Methods and Data
  - Results of Top Portfolios
  - Results of Reducing the Planning Margin
- Sample Action Plan
- Final Report Outline
- Next Steps

November 5, 2002
- Review of Draft Report

December 17, 2002
- Review of Comments on Draft Report
- Overview of Final Report

February 14, 2003
- Overview of (revised) Final Report

Public Technical Workshops

In addition to the public input meetings summarized above, a number of workshops were sponsored over the course of the planning process. These provided workshop participants with a more in-depth discussion on specific topics and technical matters. A summary of the workshops held is provided here:

- June 7 – Full-day technical workshop on risk methodology and model architecture
- June 17 – Half-day workshop on approach to demand side management issues

- June 17 – Half-day workshop on approach to renewable resource issues
- July 12 – Full-day technical workshop on modeling issues
- August 1 – Follow-on conference call on renewable resource modeling issues
- August 15 – Half-day technical modeling "chalk talk" and load/resource briefing
- August 20-21 – Load/resource briefings with participants
- September 13 – Briefing on IRP issues to PacifiCorp's Environmental Forum
- October 4 – Follow-on conference call on technical risk modeling issues
- November 19 – Half-day workshop on approach to renewables resources
- November 19 – Half-day workshop on approach to demand side management

Parking Lot Issues

During the course of the public input meetings, certain concerns needed additional explanation from PacifiCorp. In the course of the public input meetings and workshops, questions or issues were often raised which were taken off-line or put in a "parking lot." PacifiCorp either responded in writing in detail to address these parking lot issues, or in many cases, addressed them in a subsequent public input meeting or workshop. Some of the topics included:

- Modeling
  - Accounting for loss or gain of revenue in risk modeling
  - Methodology for forecasting modeling prices
- Renewable Resources
  - Wind Generation
- Competitive Wholesale Market Assumptions
  - Pricing in a fully competitive market
- Portfolios
  - Process and criteria to determine most favorable portfolio
- Risk Assessment Methodology
  - Approach for assessing risk and uncertainty in the IRP analysis reserves
  - Clarifying questions from group
- Capital Revenue Requirement
  - How it is calculated and applied in the IRP analysis

Many elements of PacifiCorp's response to parking lot items were contained in memorandums to the public input participants distributed on July 1, 2002 and August 29, 2002. PacifiCorp also responded in writing to comments and questions on wind electricity on July 24, 2002.

APPENDIX C – ASSUMPTIONS

CONTRACTS

A number of contracts were modeled in this analysis. The contract identifiers and classification (purchase, sale, or exchange) are shown in the tables C.1, C.2and C.3

Table C.1 Contracts Modeled in IRP

EXCHANGE EAST

Counterparty Name	Contract	Location	End Date	Months of Operation
Arizona Public Service Company	Seasonal Exchange Take	4C/Pinnacle Peak	01-Mar-21	Oct 15-Feb 15
Arizona Public Service Company	Seasonal Exchange Return	4C/Pinnacle Peak	01-Jan-21	May 15-Sep 15
Arizona Public Service Company	Supplemental Energy Purchase Option	4C	01-Jan-20	year round
Bonneville Power Administration	South Idaho Exchange	UT Main	na	year round
City of Redding	Exchange agreement	West Wing	01-Dec-15	year round
Public Service of Colorado	Generation Control Storage	Wyoming	01-Apr-14	year round
Public Service of Colorado	Generation Control Delivery	Craig Hayden	01-Sep-14	year round
Southern California Edison	Exchange agreement	SP15	01-Oct-06	year round
Tri-State Generation & Transmission	Seasonal Exchange Take	Wyoming	01-Oct-06	Oct-Mar
Tri-State Generation & Transmission	Seasonal Exchange Return	Wyoming	01-Apr-07	Apr-Sep

SALES EAST

Counterparty Name	Contract	Location	End Date	Months of Operation
Arizona Electric Power Cooperative	Power Sales Agreement	Westwing	01-Oct-03	May - Sep
Black Hills Corporation	Power Sales Agreement	UT Main	01-Jul-23	year round
Public Service of Colorado	Power Sales Agreement	Craig Hayden	01-Nov-22	year round
Sierra Pacific Power Company	Power Sales Agreement	Sierra	01-Mar-09	year round
Utah Municipal Power Agency	Power Sales Agreement	UT Main	01-Jul-05	year round
Utah Municipal Power Agency	Power Sales Agreement	UT Main	01-Jul-17	year round

PURCHASE EAST

Counterparty Name	Contract	Location	End Date	Months of Operation
Bonneville Power Administration	Foote Creek I and II Energy Exchange	Wyoming	28-Jun-14	year round
Bonneville Power Administration	Foote Creek IV Exchange	Wyoming	02-Oct-20	year round
Bonneville Power Administration	Rock River Wind Purchase	Wyoming	13-Nov-21	year round
Morgan Stanley	Power Purchase Option	Mona	01-Oct-04	June-Sep
Sempra	Power Purchase Option	NV-UT	01-Oct-04	June-Sep
Tri-State Generation & Transmission	Power Purchase Agreement	Wyoming	01-Jan-21	year round

LEASE EAST

Counterparty Name	Contract	Location	End Date	Months of Operation
LEASCO, a wholly owned subsidiary of PPM	West Valley	Utan	31-Dec-17	year round

Table C.1 Contracts Modeled in IRP (Continued)

EXCHANGE WEST

Counterparty Name	Contract	Location	End Date	Months of Operation
Avista Utilities	Seasonal Exchange Take	MidC	01-Jan-09	June - Sep
Avista Utilities	Seasonal Exchange Return	MidC	01-Apr-09	Dec-Feb
Bonneville Power Administration	South Idaho Exchange	West Main	na	year round
Bonneville Power Administration	Summer Storage/ Spring Energy	West Main	01-Jan-14	Jun-July, Sep-Nov
Bonneville Power Administration	Foote Creek I Wind Exchange	W Main	22-Apr-24	year round
Bonneville Power Administration	Foote Creek II Wind Exchange	W Main	01-Aug-14	year round
City of Redding	Exchange agreement	COB	01-Dec-15	year round
Colockum Transmission Company	Exchange agreement	MidC	03-Jul-03	year round
Sacramento Municipal Utility District	Exchange Agreement	COB	01-Jan-15	year round
Sacramento Municipal Utility District	Exchange agreement Take	COB	01-Jan-15	year round
Seattle City Light	Stateline Wind Exchange	MidC	01-Mar-12	year round

SALE WEST

Counterparty Name	Contract	Location	End Date	Months of Operation
Black Hills Corporation	Power Sales Agreement	Bridger/ MidC	01-Jul-23	year round
Bonneville Power Administration	Canadian Entitlement Allocation	MidC	01-Sep-18	year round
Bonneville Power Administration	Foote Creek IV Exchange	W Main	01-Dec-20	year round
California Dept of Water Resources	Firm capacity/Energy Sale	COB	01-Jan-05	year round
Eugene Water and Electric Board	BPA, Foote Creek I	W Main	22-Apr-29	year round
Flathead Energy Northwest	Power Sales Agreement	MidC	01-Oct-06	year round
Puget Sound Power and Light	Power Sales Agreement	MidC	01-Nov-03	year round
Springfield Utility Board	Power Sales Agreement	W Main	01-Aug-15	year round
Westen Area Power Administration	Power Sales Agreement	COB	01-Jan-05	year round

PURCHASE WEST

Counterparty Name	Contract	Location	End Date	Months of Operation
Bonneville Power Administration	Block Power Purchase/Clark Load Servicing Agreement	W Main	12-Dec-07	year round
TransAlta Energy Marketing	Power Purchase Agreement	W Main	30-Jun-07	year round
Hermiston Generation Company	Hermiston	W Main	30-Jun-16	year round

Table C.2 Long Term Wholesale Purchase Contracts

Long-term Wholesale Purchases
Summer Capacity (MW)

Purchases	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
APS Sea Ex (P)	-	-	-	-	-	-	-	-	-	-
APS Supplemental	250	250	250	250	250	250	250	250	250	250
BPA Block P CPU (Clark)	464	464	464	464	464	-	-	-	-	-
BPA Spring Ex (P)	-	-	-	-	-	-	-	-	-	-
BPA Foote Creek 2	1	1	1	1	1	1	1	1		
BPA Foote Creek 4	17	17	17	17	17	17	17	17	17	17
BPA Peaking Capacity Ex (P)	925	750	575	575	575	575	575	575	-	-
Colockum (P)	-	-	-	-	-	-	-	-	-	-
CSPE	5	5	5	5	5	-	-	-	-	-
Deseret Annual	-	-	-	-	-	-	-	-	-	-
Deseret Expansion	-	-	-	-	-	-	-	-	-	-
Deseret NF	-	-	-	-	-	-	-	-	-	-
Gem State	22	22	22	22	22	22	22	22	22	22
Grant County	14	14	14	14	14	14	14	14	14	14
GSLM	-	-	-	-	-	-	-	-	-	-
Idaho Load Control	150	150	150	150	150	150	150	150	150	150
Interruptible (P)	70	70	70	70	70	70	70	70	70	70
Morgan Stanley (Option)	100	100	-	-	-	-	-	-	-	-
PGE Cove	2	2	2	2	2	2	2	2	2	2
PSCO	24	24	24	24	24	24	24	24	-	-
QF Goshen	9	9	9	9	9	9	9	9	9	9
QF Or/Wa	50	50	50	50	50	50	50	50	50	50
QF Utah	50	50	50	50	50	50	50	50	50	50
QF Wyoming	3	3	3	3	3	3	3	3	3	3
Redding (P)	21	21	21	21	21	21	21	21	21	-
Rock River	50	50	50	50	50	50	50	50	50	50
SCE	200	200	200	200	-	-	-	-	-	-
Sempra (Options)	100	100	-	-	-	-	-	-	-	-
So Idaho Ex (P)	204	204	204	204	204	204	204	204	204	204
Stateline	150	150	150	150	150	150	150	150	-	-
TransAlta	400	400	400	400	400	-	-	-	-	-
Tri-State Basic	50	50	50	50	50	50	50	50	50	50
Tri-State Ex (P)	-	-	25	23	20	18	15	13	13	13
WWP Seasonal Ex (P)	50	50	50	50	50	50	-	-	-	-
WWP Summer Purchase	150	-	-	-	-	-	-	-	-	-
Purchased Power	3,530	3,205	2,855	2,853	2,650	1,779	1,726	1,724	974	953

(P) = Purchase

Table C.3 Long-Term Wholesale Sales Contracts

Long-term Wholesale Sales
Summer Capacity (MW)

	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Sales										
APS Sea Ex (S)	480	480	480	480	480	480	480	480	480	480
Black Hills 1996	-	-	-	-	-	-	-	-	-	-
Black Hills Load	55	50	50	50	50	-	-	-	-	-
BPA Foote Creek 2	1	1	1	1	1	1	1	1		
BPA Foote Creek4	17	17	17	17	17	17	17	17	17	17
BPA Spring Ex (S)	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (S)	-	-	-	-	-	-	-	-	-	-
BPA Wind Sale	6	6	6	6	6	6	6	6	6	6
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-
CDWR	100	100	-	-	-	-	-	-	-	-
Citizens Power	-	-	-	-	-	-	-	-	-	-
Clark County PUD	-	-	-	-	-	-	-	-	-	-
Clark-WT	-	-	-	-	-	-	-	-	-	-
Colockum (S)	-	-	-	-	-	-	-	-	-	-
Deseret Supplemental	-	-	-	-	-	-	-	-	-	-
EWEB	9	9	9	9	9	9	9	9	9	9
Green Mountain	-	-	-	-	-	-	-	-	-	-
Hinson	-	-	-	-	-	-	-	-	-	-
Hurricane Net Sale	3	3	3	3	3	-	-	-	-	-
Large Industrials	367	367	367	367	367	367	367	367	367	367
Montana Sell Back	70	70	70	70	-	-	-	-	-	-
Okanogan	-	-	-	-	-	-	-	-	-	-
PNGC	-	-	-	-	-	-	-	-	-	-
PSCO	24	24	24	24	24	24	24	24	-	-
PSCO	176	176	176	176	176	176	176	176	176	176
Puget 2	200	-	-	-	-	-	-	-	-	-
Redding (S)	50	50	50	50	50	50	50	50	-	-
SCE OWC	200	200	200	200	-	-	-	-	-	-
SCE Utah	-	-	-	-	-	-	-	-	-	-
Sierra 2	75	75	75	75	75	75	75	-	-	-
SMUD	100	100	100	100	100	100	100	100	-	-
So Idaho Ex (S)	204	204	204	204	204	204	204	204	204	204
Springfield	50	50	50	50	50	50	50	50	50	-
Springfield II	-	-	-	-	-	-	-	-	-	-
Stateline	55	55	55	55	55	55	55	55		
Tri-State Ex (S)	50	50	50	50	-	-	-	-	-	-
UMPA 1	8	8	8	-	-	-	-	-	-	-
UMPA 2	25	25	25	25	25	25	25	25	25	25
WAPA 1	-	-	-	-	-	-	-	-	-	-
WAPA 2	53	53	-	-	-	-	-	-	-	-
WWP Seasonal Ex (S)	-	-	-	-	-	-	-	-	-	-
Total Sales	2,378	2,173	2,020	2,012	1,692	1,639	1,639	1,564	1,334	1,284

(S) = Sale

DEMAND SIDE MANAGEMENT (DSM) – EXISTING

DSM is currently included in the load forecast. The details of existing DSM projects are presented below. Future DSM projects are discussed in Appendix G.
The following applies to all programs in all states:

- **Description of Project**: Program to provide technical assistance and financial incentives for commercial and industrial customers to permanently install energy efficiency measures at their facilities
- **Life of Project**: Aggregate program results deliver 15 years of savings. Programs are run for 10 years at the same level. Savings after the end of the measured life are unknown and while measures are likely to be replaced with measures of equal or greater efficiency, the cost to "maintain" that savings and any degradation is not quantified here.
- **Timing of Savings**: The majority of commercial and industrial savings occur during heavy load hours in addition to light load hours
- **Savings** are all at site and should be "grossed" up for line losses. Industrial line losses are 9.06% for evaluations. Evaluation minus commercial line losses = 11.48%
- **Program results** are in aggregate and are comprised of individual projects. Results and costs are based on prior "as run" experience in Oregon, Washington and Utah. Program performance varies slightly depending on measure installations and vertical market segments. Those assumptions are averaged for the purposes of this analysis
- **Fiscal year vs. calendar year**: costs and savings are listed for calendar 2003.

Table C.4 DSM All-State Summary

Total Annual Residential, Commercial, and Industrial Program Targets			
Fiscal Year	**MWa**	**MWH**	**$**
2003	18.76	164,316	33,353,742
2004	18.99	166,345	33,426,007
2005	20.15	176,546	31,395,328
2006	18.02	157,880	23,188,147
2007	14.54	127,390	22,464,000
2008	14.06	123,205	21,934,000
2009	14.06	123,205	21,934,000
2010	14.06	123,205	21,934,000
2011	14.06	123,205	21,934,000
2012	14.06	123,205	21,934,000

Tables C.5, C.6, C.7, C.8 and C.9 summarize demand side management programs by state.

Table C.5 Idaho DSM Projects

ID Small Retrofit

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	0.15	1,314	1,500,000	225,000
2005	0.15	1,314	1,400,000	210,000
2006	0.15	1,314	1,400,000	210,000
2007	0.15	1,314	1,400,000	210,000
2008	0.15	1,314	1,400,000	210,000
2009	0.15	1,314	1,400,000	210,000
2010	0.15	1,314	1,400,000	210,000
2011	0.15	1,314	1,400,000	210,000
2012	0.15	1,314	1,400,000	210,000

ID annual summary

Fiscal Year	Mwa	MWH	$$
2004	1.38	12,080	2,429,400
2005	1.39	12,207	2,365,400
2006	1.23	10,771	1,921,000
2007	1.12	9,783	1,710,000
2008	1.01	8,823	1,560,000
2009	1.01	8,823	1,560,000
2010	1.01	8,823	1,560,000
2011	1.01	8,823	1,560,000
2012	1.01	8,823	1,560,000

ID Large Retrofit

Fiscal Year	Mwa	MWH	M/Mwa	
2004	0.25	2,190	1,500,000	375,000
2005	0.25	2,190	1,400,000	350,000
2006	0.25	2,190	1,400,000	350,000
2007	0.25	2,190	1,400,000	350,000
2008	0.25	2,190	1,400,000	350,000
2009	0.25	2,190	1,400,000	350,000
2010	0.25	2,190	1,400,000	350,000
2011	0.25	2,190	1,400,000	350,000
2012	0.25	2,190	1,400,000	350,000

ID Res - CFL

Fiscal Year	Mwa	MWH	
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

ID Energy FinAnswer

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	0.6	5,256	1,600,000	960,000
2005	0.6	5,256	1,500,000	900,000
2006	0.6	5,256	1,500,000	900,000
2007	0.6	5,256	1,500,000	900,000
2008	0.6	5,256	1,500,000	900,000
2009	0.6	5,256	1,500,000	900,000
2010	0.6	5,256	1,500,000	900,000
2011	0.6	5,256	1,500,000	900,000
2012	0.6	5,256	1,500,000	900,000

ID Res - High efficency CAC

Fiscal Year	Mwa	MWH	$$
2004	0.1128	988	277,000
2005	0.1273	1,115	313,000
2006	0.1128	988	211,000
2007			
2008			
2009			
2010			
2011			
2012			

ID Res - AC Best Practices service

Fiscal Year	Mwa	MWH	$$
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

8-28-02 deleted from inputs based on preliminary screening. PTCS from Alliance is logical replacement.

ID Res - Appliance recycle

Fiscal Year	Mwa	MWH	$$
2004	0.1494	1,309	342,400
2005	0.1494	1,309	342,400
2006			
2007			
2008			
2009			
2010			
2011			
2012			

Table C.5 Idaho DSM Projects (Continued)

ID Res - Low Income WX

Fiscal Year	Mwa	MWH	$$
2004	0.0072	63	100,000
2005	0.0072	63	100,000
2006			
2007			
2008			
2009			
2010	0.0072	63	100,000
2011	0.0072	63	100,000
2012	0.0072	63	100,000
2013	0.0072	63	100,000
2014	0.0072	63	100,000
2015	0.0072	63	100,000
2016	0.0072	63	100,000
2017	0.0072	63	100,000
2018	0.0072	63	100,000
2019	0.0072	63	100,000
2020	0.0072	63	100,000
2021	0.0072	63	100,000
2022	0.0072	63	100,000

8-28-02 deleted from inputs based on preliminary screening. Alliance is logical primary delivery channel.

ID Res - Energy Star Appliances - electric water heat only

Fiscal Year	Mwa	MWH	$$
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

ID Res - Web Audit

Fiscal Year	Mwa	MWH	$$
2004	0.1096	960	150,000
2005	0.1096	960	150,000
2006	0.1096	960	150,000
2007	0.1096	960	150,000
2008			
2009			
2010			
2011			
2012			

Table C.6 Washington DSM Projects

WA Small Retrofit

FiscalYear	Mwa	MWH	$M/Mwa	$$
2004	0.2600	2,278	1,500,000	390,000
2005	0.2600	2,278	1,400,000	364,000
2006	0.2600	2,278	1,400,000	364,000
2007	0.2600	2,278	1,400,000	364,000
2008	0.2600	2,278	1,400,000	364,000
2009	0.2600	2,278	1,400,000	364,000
2010	0.2600	2,278	1,400,000	364,000
2011	0.2600	2,278	1,400,000	364,000
2012	0.2600	2,278	1,400,000	364,000

WA total annual

FiscalYear	Mwa	MWH	$$
2004	2.5802	22,603	3,894,969
2005	2.6155	22,912	4,433,075
2006	2.3452	20,544	4,187,147
2007	2.0710	18,142	3,674,000
2008	1.7970	15,742	3,424,000
2009	1.7970	15,742	3,424,000
2010	1.7970	15,742	3,424,000
2011	1.7970	15,742	3,424,000
2012	1.7970	15,742	3,424,000

WA Large Retrofit

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	0.4000	3,504	1,500,000	600,000
2005	0.4000	3,504	1,400,000	560,000
2006	0.4000	3,504	1,400,000	560,000
2007	0.4000	3,504	1,400,000	560,000
2008	0.4000	3,504	1,400,000	560,000
2009	0.4000	3,504	1,400,000	560,000
2010	0.4000	3,504	1,400,000	560,000
2011	0.4000	3,504	1,400,000	560,000
2012	0.4000	3,504	1,400,000	560,000

WA Res - CFL

Fiscal Year	Mwa	MWH	$$
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

WA Energy FinAnswer

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	1.0000	8,760	1,600,000	1,600,000
2005	1.0000	8,760	1,500,000	1,500,000
2006	1.0000	8,760	1,500,000	1,500,000
2007	1.0000	8,760	1,500,000	1,500,000
2008	1.0000	8,760	1,500,000	1,500,000
2009	1.0000	8,760	1,500,000	1,500,000
2010	1.0000	8,760	1,500,000	1,500,000
2011	1.0000	8,760	1,500,000	1,500,000
2012	1.0000	8,760	1,500,000	1,500,000

WA Res - High efficency CAC

Fiscal Year	Mwa	MWH	$$
2004	0.2739	2,399	672,969
2005	0.3091	2,708	759,075
2006	0.2742	2,402	513,147
2007			
2008			
2009			
2010			
2011			
2012			

WA Res - AC Best Practices service

Fiscal Year	Mwa	MWH	$$
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

8-28-02 deleted from inputs based on preliminary screening. PTCS from Alliance is logical replacement.

WA Res - Web Audit

Fiscal Year	Mwa	MWH	$$
2004	0.2740	2,400	250,000
2005	0.2740	2,400	250,000
2006	0.2740	2,400	250,000
2007	0.2740	2,400	250,000
2008			
2009			
2010			
2011			
2012			

Table C.6 Washington DSM Projects (Continued)

WA Res - Low Income WX

Fiscal Year	Mwa	MWH	$$
2004	0.1370	1,200	1,000,000
2005	0.1370	1,200	1,000,000
2006	0.1370	1,200	1,000,000
2007	0.1370	1,200	1,000,000
2008	0.1370	1,200	1,000,000
2009	0.1370	1,200	1,000,000
2010	0.1370	1,200	1,000,000
2011	0.1370	1,200	1,000,000
2012	0.1370	1,200	1,000,000
2013	0.1370	1,200	1,000,000
2014	0.1370	1,200	1,000,000
2015	0.1370	1,200	1,000,000
2016	0.1370	1,200	1,000,000
2017	0.1370	1,200	1,000,000
2018	[illegible]	[illegible]	[illegible]
2019	[illegible]	[illegible]	[illegible]
2020	[illegible]	[illegible]	[illegible]
2021	[illegible]	[illegible]	[illegible]
2022	0.1370	1,200	1,000,000

8-28-02 Deleted from inputs based on preliminary screening. Alliance would be logical primary delivery channel.

WA Res - Appliance recycle

Fiscal Year	Mwa	MWH	$$
2004	0.2354	2,062	382,000
2005	0.2354	2,062	382,000
2006			
2007			
2008			
2009			
2010			
2011			
2012			

WA Res - Energy Star Appliances

Fiscal Year	Mwa	MWH	$$
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

Table C.7 Wyoming DSM Projects

WY Small Retrofit

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	0.25	2,190	1,500,000	375,000
2005	0.25	2,190	1,400,000	350,000
2006	0.25	2,190	1,400,000	350,000
2007	0.25	2,190	1,400,000	350,000
2008	0.25	2,190	1,400,000	350,000
2009	0.25	2,190	1,400,000	350,000
2010	0.25	2,190	1,400,000	350,000
2011	0.25	2,190	1,400,000	350,000
2012	0.25	2,190	1,400,000	350,000

WY total annual

Fiscal Year	Mwa	MWH	$$
2004	2.08	18,220	3,381,490
2005	2.09	18,278	3,215,340
2006	1.75	15,330	2,550,000
2007	2.00	17,520	2,925,000
2008	2.00	17,520	2,925,000
2009	2.00	17,520	2,925,000
2010	2.00	17,520	2,925,000
2011	2.00	17,520	2,925,000
2012	2.00	17,520	2,925,000

WY Large Retrofit

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	0.5	4,380	1,500,000	750,000
2005	0.5	4,380	1,400,000	700,000
2006	0.5	4,380	1,400,000	700,000
2007	0.5	4,380	1,400,000	700,000
2008	0.5	4,380	1,400,000	700,000
2009	0.5	4,380	1,400,000	700,000
2010	0.5	4,380	1,400,000	700,000
2011	0.5	4,380	1,400,000	700,000
2012	0.5	4,380	1,400,000	700,000

WY Res - CFL

Fiscal Year	Mwa	MWH	$$
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

WY Energy FinAnswer

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	1	8,760	1,600,000	1,600,000
2005	1	8,760	1,500,000	1,500,000
2006	1	8,760	1,500,000	1,500,000
2007	1.25	10,950	1,500,000	1,875,000
2008	1.25	10,950	1,500,000	1,875,000
2009	1.25	10,950	1,500,000	1,875,000
2010	1.25	10,950	1,500,000	1,875,000
2011	1.25	10,950	1,500,000	1,875,000
2012	1.25	10,950	1,500,000	1,875,000

WY Res - Appliance recycle

Fiscal Year	Mwa	MWH	$/Mwa
2004	0.3186	2,791	548,640
2005	0.3186	2,791	548,640
2006			
2007			
2008			
2009			
2010			
2011			
2012			

WY Res - Energy Star Appliances -electric water heat only

FiscalYear	Mwa	MWH	
2004	0.0114	99	107,850
2005	0.0180	157	116,700
2006			
2007			
2008			
2009			
2010			
2011			
2012			

Table C.8 Utah DSM Projects

UT Small Retrofit

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	1	8,760	1,500,000	1,500,000
2005	1	8,760	1,400,000	1,400,000
2006	1	8,760	1,400,000	1,400,000
2007	1	8,760	1,400,000	1,400,000
2008	1	8,760	1,400,000	1,400,000
2009	1	8,760	1,400,000	1,400,000
2010	1	8,760	1,400,000	1,400,000
2011	1	8,760	1,400,000	1,400,000
2012	1	8,760	1,400,000	1,400,000

UT total annual

Fiscal Year	Mwa	MWH	$$
2004	12.43	108,891	20,645,642
2005	13.70	120,044	22,690,148
2006	12.34	108,130	20,001,513
2007	9.00	78,840	13,150,000
2008	9.00	78,840	13,150,000
2009	9.00	78,840	13,150,000
2010	9.00	78,840	13,150,000
2011	9.00	78,840	13,150,000
2012	9.00	78,840	13,150,000

UT Large Retrofit

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	2	17,520	1,500,000	3,000,000
2005	2.5	21,900	1,400,000	3,500,000
2006	2.5	21,900	1,400,000	3,500,000
2007	2.5	21,900	1,400,000	3,500,000
2008	2.5	21,900	1,400,000	3,500,000
2009	2.5	21,900	1,400,000	3,500,000
2010	2.5	21,900	1,400,000	3,500,000
2011	2.5	21,900	1,400,000	3,500,000
2012	2.5	21,900	1,400,000	3,500,000

UT Res - CFL

Fiscal Year	Mwa	MWH	$$
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

UT Energy FinAnswer

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	5	43,800	1,600,000	8,000,000
2005	5.5	48,180	1,500,000	8,250,000
2006	5.5	48,180	1,500,000	8,250,000
2007	5.5	48,180	1,500,000	8,250,000
2008	5.5	48,180	1,500,000	8,250,000
2009	5.5	48,180	1,500,000	8,250,000
2010	5.5	48,180	1,500,000	8,250,000
2011	5.5	48,180	1,500,000	8,250,000
2012	5.5	48,180	1,500,000	8,250,000

UT Res - Coupon CFL

Fiscal Year	Mwa	MWH	$$
2004	0.43	3,770	250,000
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

UT Res - High efficency CAC

Fiscal Year	Mwa	MWH	$$
2004	2.0140	17,643	3,958,642
2005	2.2734	19,915	4,465,148
2006	2.0167	17,666	3,018,513
2007			
2008			
2009			
2010			
2011			
2012			

UT Res - AC Best Practices service

Fiscal Year	Mwa	MWH	$$
2004	0.1575	1,380	770,000
2005	0.3973	3,480	1,645,000
2006	0.5479	4,800	2,085,000
2007			
2008			
2009			
2010			
2011			
2012			

Table C.8 Utah DSM Projects (Continued)

UT Res - Appliance recycle

Fiscal Year	Mwa	MWH	$/Mwa
2004	1.7313	15,166	2,247,000
2005	1.7313	15,166	2,247,000
2006			
2007			
2008			
2009			
2010			
2011			
2012			

UT Res - Energy Star Appliances -electric water heat only

Fiscal Year	Mwa	MWH	$$
2004	0.0408	357	654,000
2005	0.0757	663	719,000
2006	0.1197	1,049	778,000
2007			
2008			
2009			
2010			
2011			
2012			

UT C&I retro-commissioning - 1.5kWh/SF

Fiscal Year	Mwa	MWH	$$
2004	0.0565	495	266,000
2005	0.2260	1,980	464,000
2006	0.6592	5,775	970,000
2007			
2008			
2009			
2010			
2011			
2012			

Table C.9 California DSM Projects

CA Retrofit - Combined

Fiscal Year	Mwa	MWH	$M/Mwa	$$
2004	0.25	2,190	1,600,000	400,000
2005	0.25	2,190	1,600,000	400,000
2006	0.25	2,190	1,600,000	400,000
2007	0.25	2,190	1,600,000	400,000
2008	0.25	2,190	1,600,000	400,000
2009	0.25	2,190	1,600,000	400,000
2010	0.25	2,190	1,600,000	400,000
2011	0.25	2,190	1,600,000	400,000
2012	0.25	2,190	1,600,000	400,000

CA total annual

Fiscal Year	Mwa	MWH	$$
2004	0.35	3,105	680,000
2005	0.35	3,105	680,000
2006	0.35	3,105	680,000
2007	0.35	3,105	680,000
2008	0.26	2,280	550,000
2009	0.26	2,280	550,000
2010	0.26	2,280	550,000
2011	0.26	2,280	550,000
2012	0.26	2,280	550,000

CA Res - CFL

Fiscal Year	Mwa	MWH	$$
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

CA Res - Web Audit

Fiscal Year	Mwa	MWH	$$
2004	0.0942	825	130,000
2005	0.0942	825	130,000
2006	0.0942	825	130,000
2007	0.0942	825	130,000
2008			
2009			
2010			
2011			
2012			

CA Res - Low Income WX

Fiscal Year	Mwa	MWH	$$
2004	0.0103	90	150,000
2005	0.0103	90	150,000
2006	0.0103	90	150,000
2007	0.0103	90	150,000
2008	0.0103	90	150,000
2009	0.0103	90	150,000
2010	0.0103	90	150,000
2011	0.0103	90	150,000
2012	0.0103	90	150,000
2013	0.0103	90	150,000
2014	0.0103	90	150,000
2015	0.0103	90	150,000
2016	0.0103	90	150,000
2017	0.0103	90	150,000
2018	0.0103	90	150,000
2019	0.0103	90	150,000
2020	0.0103	90	150,000
2021	0.0103	90	150,000
2022	0.0103	90	150,000

EMISSION COSTS

Note all costs referred to in this Emission Costs Assumption section are per calendar year.

SO2 Emission Costs

Current vintage SO_2 allowances are trading within the \$140/ton to \$150/ton range, with future vintage SO_2 allowances (2005) currently trading at similar price levels. Lowering the SO_2 cap in general will place upward pressure on SO_2 allowance prices. However, this will most likely be balanced with the downward pressure associated with $PM_{2.5}$ and Hg regulations that will encourage additional scrubbers and related technology. As a result, long-term allowance prices are likely to only increase at a modest rate, although numerous uncertainties exist related to the timing and nature of future legislation that will effect to what extent prices will change.

Table C.10 lists the SO_2 emission costs used in the IRP. The prices are derived from PIRA projections that prices would need to move from \$175/ton in 2002 up to \$350/ton to \$400/ton in order for credit prices alone to achieve the current Clean Air Act Amendment of 1990 (CAAA90) annual SO_2 cap for 2009 at 8.98 million tons. For the IRP, this upper price range was slightly modified to take into account the downward pressure of Hg and $PM_{2.5}$ regulations.

Table C.10 SO2 Emission Costs

SO2 Emission Costs

Year	$/ton SO2
2003	199
2004	226
2005	256
2006	291
2007	330
2008	375
After 2008	2.5% escalation/year[17]

NOx Emission Costs

Current vintage NO_x allowances (within the OTC trading regime) are trading within the \$600-700/ton range, with future vintage allowances trading within the \$4,200 to 4,900/ton range (the dramatic change in price due to the prescribed decline in allowance allocations for OTC participants beginning in 2003). For non-OTC participants, NO_x emission standards will not be of issue until future legislation is enacted (with the exception of units subject to the South Coast Air Quality Management District (SCAQMD) in Southern California which oversees the RECLAIM emissions trading program). As with SO_2, NO_x prices will receive upward pressure from a lower emission cap, but will be balanced by a downward pressure from $PM_{2.5}$ regulations.

[17] 2.5% is the standard inflation rate assumed by PacifiCorp

Table C.11 lists the NO_x compliance costs used in the IRP. SCAQMD prices are incorporated only as a factor affecting electricity market prices.[18] Otherwise, NO_x emission costs were derived from PIRA's assessment that $2,000/ton in 2002 is "roughly in line with SCR costs if computed on a year round basis," which was then escalated at 2.5% until 2008 when NO_x allowance trading is forecasted to start.

Table C.11 NOx Emission Costs

NO_x Emission Costs

	2002	2005	2008
SCAQMD	$15,000/ton	$5,000/ton	$5,384/ton
WECC (excluding CA)	N/A	N/A	$2,319/ton

Mercury (Hg) Emission Costs

Hg was addressed in the CAAA90 under the National Emissions Standards for Hazardous Air Pollutants (NESHAPS) regulations, yet source identification and associated rules are not currently defined/enforced. However, through either current proposed federal legislation or the promulgation of Hg standards from the EPA through the MACT regulations, the need for Hg emission compliance is expected by 2007/2008.

Hg emission costs were implemented starting in 2008 at $231,939,000/ton ($115,969/lb), then escalating at 2.5%/year through the remainder of the study period. This value was derived from PIRA data that cites an EPA estimate that $100,000/lb in 2002 reflects the "marginal cost to achieve reductions in Hg emissions by electricity producers to 7.5 tons in year 2012," in association with NO_x and SO_2 reductions. This was then escalated at 2.5%/year until 2008 when Hg allowance trading is assumed to start.

CO2 Emission Costs

There are currently no national regulated standards for CO_2 emissions, although there exist voluntary emission reduction programs and trading markets. S.556 incorporates mandatory CO_2 emission reductions and the establishment of a related trading market, but it remains a significantly contentious issue. In addition, the Kyoto Protocol (although not ratified by the U.S.) may still play an indirect role in terms of placing pressure on U.S. corporations to voluntarily reduce greenhouse gas (GHG) reductions. Other factors include existing and potential state-level regulations as state officials react to public concern.

With all the uncertainty surrounding future GHG reduction legislation, cost adders were chosen as the best method to reflect the wide array of potential offset costs. The base case CO_2 adder was set at $8/ton CO_2 starting in 2008, then escalating at 2.5%/year for the remainder of the study period. This adder is based on the higher end of the range of currently available offsets and is in line with the cost of compliance tools emerging internationally. The timing and price assumes the following policy scenario:

[18] The SCAQMD 2002 price reflects the pure market-derived price structure at the time. 2005 is based on the current cap implemented during the CA energy crisis. 2008 is derived from escalating the 2005 price by 2.5%/year.

- No action on climate issues until the end of the next Presidential cycle (2008)
- Actions will require reductions of all utility players, with some modest limits on flexibility
- Early trades in emerging markets provide an accurate estimate for the price of reductions in the U.S.

Particulate Matter

Compliance costs associated with the pending $PM_{2.5}$ regulation were not modeled as an additional cost factor.

EMISSION RATES

Data on plant emission for this analysis were derived primarily from two sources: the EPA Continuous Emissions Monitoring System (CEMS), and FERC Form 423. The EPA Continuous Emissions Monitoring System includes hourly operational data for approximately 2,800 individual generators in the NERC regions.

SO2 Emission Rates

The SO_2 emission rates for coal fuels are updated using data on coal delivered at each coal plant reported in the 2000 FERC Form 423 data. The 2000 FERC Form 423 fuel data reports the sulfur content, the amount of coal (tons) and the energy content (Btu) for all coal deliveries at each reporting plant. Calculations are then performed to determine the uncontrolled SO_2 emission rates (lb/MMBtu) for many of the coal fuels in the NERC regions. Estimates of average emission rates based upon coal type and region are also performed. The average emission rates by coal type and region are then used to estimate the SO_2 emission rates for coal plant without any reported data.

For plants where the future installation date of emission controls could be projected, calculations of emission rates prior to emission control technology were derived from the SO_2 content in the coal (lb/MMBtu) and percent removal/ SO_2 retention data. For all other plants, 2001 historical data was used.

Calculations of emission rates after emission control technology (i.e. scrubbers) were performed using actual SO_2 emissions data from the 2000 EPA CEMS data. For controlled units emissions will be controlled below the state limit. For coal units that did not report any data, average SO_2 removal rates are assigned based upon plants of similar age, fuel, and region

NOx Emission Rates

Year 2000 EPA CEMS data was used to model NO_x emission rates (lbs/MMBtu) for generating units that reported to the EPA. Units that did not report emission data to the EPA had NO_x emission rates estimated based upon plants of similar fuel type, unit type, and age. NO_x emissions reductions projected to occur at a number of coal plants over the next few years were also included in the database. PacifiCorp plant NO_x emission rates were also based on CEMS data.

Mercury Emission Rates

Mercury (Hg) emission rates were based on the EPA/EPRI Study: *An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants, October 2000.*

Carbon Emission Rates

CO_2 emission rates are based on Continuos Emission Monitor (CEM) data from each of the plants.

EXISTING PLANT COSTS

Only incremental costs between proposals were analyzed. Ongoing fixed costs related to existing plants and contracts, such as fixed O&M, ongoing capital costs for overhauls, and current plant in-service balances were ignored because they are the same under all scenarios.

FUEL COSTS

The Tables C.12 and C.13 along with Figure C.1 below summarize the fuel cost inputs. Natural gas prices were developed from blending the August 1, 2002 "near-term forward prices from market" forecast (produced internally) with PIRA's long term gas forecast dated March 12, 2002. The blending method utilized was the same as the method used in determining market prices, which is described later in this appendix. Coal prices were developed from PacifiCorp Fuel Resources forecasts.

Table C.12 Annual Average Natural Gas Prices

Annual Average Natural Gas Prices MidC & Utah (\$/MMBtu)		
Fiscal Year	**Mid C**	**Utah**
2004	\$3.81	\$3.63
2005	\$3.96	\$3.77
2006	\$4.00	\$3.82
2007	\$4.22	\$4.04
2008	\$4.42	\$4.26
2009	\$4.29	\$4.14
2010	\$3.77	\$3.65
2011	\$3.91	\$4.01
2012	\$4.40	\$4.53
2013	\$4.64	\$4.77
2014	\$4.45	\$4.53
2015	\$4.88	\$4.97
2016	\$5.10	\$5.20
2017	\$5.22	\$5.32
2018	\$5.34	\$5.44
2019	\$5.46	\$5.57
2020	\$5.59	\$5.70
2021	\$5.68	\$5.79
2022	\$5.72	\$5.83
2023	\$5.85	\$5.97

Figure C.1 Annual Average Natural Gas Prices

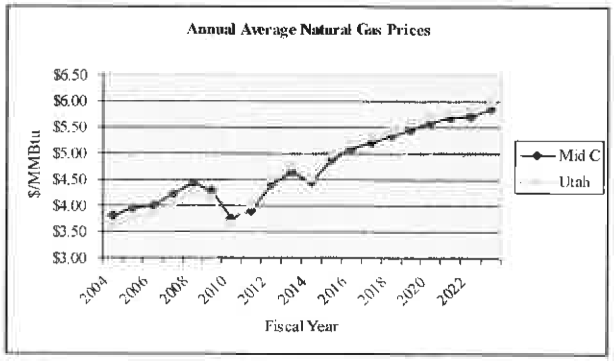


Table C.13 Annual Average Coal Prices for each of the PacifiCorp owned plants

Annual Average Deliverd Coal Price by Plant ($/MMBtu)

Fiscal Year	Cholla	Colstrip	Carbon	Hunter	Huntington	Hayden	Craig	Bridger	Johnston	Naughton	Wyodak
2004	$1.21	$0.63	$0.68	$0.74	$0.77	$1.08	$1.03	$1.10	$0.57	$1.13	$0.60
2005	$1.24	$0.66	$0.60	$0.71	$0.80	$1.08	$1.03	$1.13	$0.52	$1.14	$0.61
2006	$1.28	$0.68	$0.58	$0.72	$0.81	$1.03	$1.03	$1.17	$0.51	$1.17	$0.63
2007	$1.33	$0.71	$0.60	$0.75	$0.78	$0.96	$1.02	$1.19	$0.53	$1.20	$0.64
2008	$1.36	$0.77	$0.59	$0.77	$0.74	$0.94	$1.04	$1.21	$0.54	$1.23	$0.66
2009	$1.40	$0.82	$0.60	$0.79	$0.74	$0.94	$1.07	$1.24	$0.55	$1.26	$0.68
2010	$1.43	$0.84	$0.62	$0.81	$0.78	$0.92	$1.10	$1.27	$0.57	$1.28	$0.69
2011	$1.46	$0.85	$0.63	$0.83	$0.80	$0.93	$1.13	$1.30	$0.58	$1.31	$0.71
2012	$1.49	$0.86	$0.65	$0.85	$0.82	$0.95	$1.13	$1.33	$0.60	$1.34	$0.73
2013	$1.53	$0.88	$0.67	$0.87	$0.84	$0.97	$1.16	$1.36	$0.61	$1.37	$0.74
2014	$1.56	$0.90	$0.68	$0.89	$0.86	$0.99	$1.18	$1.39	$0.62	$1.39	$0.76
2015	$1.59	$0.92	$0.70	$0.91	$0.88	$1.01	$1.21	$1.41	$0.63	$1.42	$0.77
2016	$1.62	$0.94	$0.71	$0.92	$0.90	$1.03	$1.23	$1.44	$0.65	$1.45	$0.79
2017	$1.66	$0.96	$0.73	$0.94	$0.91	$1.05	$1.26	$1.47	$0.66	$1.49	$0.81
2018	$1.69	$0.98	$0.74	$0.96	$0.93	$1.07	$1.29	$1.51	$0.67	$1.52	$0.82
2019	$1.73	$1.00	$0.76	$0.98	$0.95	$1.10	$1.31	$1.54	$0.69	$1.55	$0.84
2020	$1.77	$1.02	$0.77	$1.01	$0.97	$1.12	$1.34	$1.57	$0.70	$1.58	$0.86
2021	$1.80	$1.04	$0.79	$1.03	$1.00	$1.14	$1.37	$1.60	$0.72	$1.62	$0.88
2022	$1.84	$1.06	$0.81	$1.05	$1.02	$1.17	$1.40	$1.64	$0.73	$1.65	$0.89
2023	$1.88	$1.08	$0.82	$1.07	$1.04	$1.19	$1.43	$1.67	$0.75	$1.68	$0.91

HEAT RATES FOR THERMAL PLANTS

Table C.14 Thermal Plant Heat Rates

FY 2003 Budget - Revised Heat Rate Targets

	Units	CB1	CB2	Cholla 4	Colstrip 3	Colstrip 4	Craig 1	Craig 2	DJ1	DJ2	DJ3	DJ4	GA1	GA2
100% Capacity														
Net Dependable Rating, 100%	MW	70	105	380	740	740	428	428	106	106	230	330	60	75
Minimum	MW	20	30	300	245	245	130	130	25	25	70	120	17	20
PacifiCorp Share of Capacity														
%	$	100.00%	100.00%	100.00%	10.00%	10.00%	19.28%	19.28%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Net Dependable Rating	MW	70	105	380	74	74	83	83	106	106	230	330	60	75
Minimum	MW	20	30	300	25	25	25	25	25	25	70	120	17	20
Heat Rate														
100% Load	MW	70	105	380	74	74	83	83	106	106	230	330	60	75
100% Heat Rate	BTU/KWh	11,159	10,964	10,597	11,198	11,198	10,039	10,217	11,082	11,242	11,227	11,263	13,270	12,710
85% Load	MW	60	89	323	63	63	70	70	90	90	196	281	51	64
85% Heat Rate	BTU/KWh	11,535	11,230	10,711	11,342	11,342	10,074	10,253	10,813	10,716	10,919	11,219	13,210	12,673
70% Load	MW	49	74	266	52	52	58	58	74	74	161	231	42	53
70% Heat Rate	BTU/KWh	12,076	11,617	10,906	11,571	11,571	10,179	10,360	10,651	10,304	10,685	11,237	13,303	12,720
55% Load	MW	39	58	209	41	41	45	45	58	58	127	182	33	41
55% Heat Rate	BTU/KWh	12,919	12,221	11,250	11,955	11,955	10,409	10,594	10,680	10,098	10,587	11,367	13,671	12,920
Minimum Load	MW	20	30	300	25	25	25	25	25	25	70	120	17	20
Minimum Load Heat Rate	BTU/KWh	16,582	14,862	10,777	13,231	13,231	11,543	11,748	12,986	12,077	11,247	11,895	16,369	14,634

Note: CB = Carbon
DJ = Dave Johnston
GA = Gadsby

Table C.14 Thermal Plant Heat Rates (Continued)

FY 2003 Budget - Revised Heat Rate Targets

	Units	GA3	Hayden 1	Hayden 2	Herm 1	Herm 2	HR1	HR2	HR3	HN1	HN2	JB1	JB2	JB3
100% Capacity														
Net Dependable Rating, 100%	MW	100	184	262	237	238	430	430	460	440	455	530	530	530
Minimum	MW	25	73	103	154	154	172	172	184	176	182	200	200	200
PacifiCorp Share of Capacity														
%	$	100.00%	24.50%	12.60%	50.00%	50.00%	93.75%	60.31%	100.00%	100.00%	100.00%	66.67%	66.67%	66.67%
Net Dependable Rating	MW	100	45	33	118.5	118.8	403	259	460	440	455	353	353	353
Minimum	MW	25	18	13	77	77	161	104	184	176	182	133	133	133
Heat Rate														
100% Load	MW	100	45	33	119	119	403	259	460	440	455	353	353	353
100% Heat Rate	BTU/KWh	11,144	10,380	10,296	7,241	7,222	10,401	10,386	10,294	10,226	9,971	10,445	10,419	10,554
85% Load	MW	85	38	28	101	101	343	220	391	374	387	300	300	300
85% Heat Rate	BTU/KWh	11,285	10,510	10,341	7,362	7,335	10,505	10,467	10,327	10,310	9,958	10,389	10,262	10,403
70% Load	MW	70	32	23	83	83	282	182	322	308	319	247	247	247
70% Heat Rate	BTU/KWh	11,528	10,742	10,474	7,652	7,562	10,686	10,627	10,434	10,470	10,020	10,423	10,195	10,339
55% Load	MW	55	25	18	65	65	222	143	253	242	250	194	194	194
55% Heat Rate	BTU/KWh	11,958	11,162	10,766	8,250	7,997	11,008	10,930	10,675	10,768	10,215	10,618	10,291	10,436
Minimum Load	MW	25	18	13	77	77	161	104	184	176	182	133	133	133
Minimum Load Heat Rate	BTU/KWh	14,713	11,979	11,435	7,808	7,682	11,630	11,537	11,200	11,359	10,695	11,292	10,855	10,995

Note: GA = Gadsby
HR = Hermiston
HN = Huntington
JB = Jim Bridger

Table C.14 Thermal Plant Heat Rates (Continued)

FY 2003 Budget - Revised Heat Rate Targets

	Units	JB4	NT1	NT2	NT3	WY	Gadsby 4	Gadsby 5	Gadsby 6	WV 1	WV 2	WV 3	WV 4	WV 5
100% Capacity														
Net Dependable Rating, 100%	MW	530	160	210	330	335	40	40	40	40	40	40	40	40
Minimum	MW	200	80	105	200	180	10	10	10	10	10	10	10	10
PacifiCorp Share of Capacity														
%	$	66.67%	100.00%	100.00%	100.00%	80.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Net Dependable Rating	MW	353	160	210	330	268	40	40	40	40	40	40	40	40
Minimum	MW	133	80	105	200	144	10	10	10	10	10	10	10	10
Heat Rate														
100% Load	MW	353	160	210	330	268	40	40	40	40	40	40	40	40
100% Heat Rate	BTU/KWh	10,523	10,658	10,612	10,524	11,893	10,006	10,006	10,006	10,006	10,006	10,006	10,006	10,006
85% Load	MW	300	136	179	281	228	34	34	34	34	34	34	34	34
85% Heat Rate	BTU/KWh	10,374	10,632	10,546	10,361	11,968	10,405	10,405	10,405	10,405	10,405	10,405	10,405	10,405
70% Load	MW	247	112	147	231	188	28	28	28	28	28	28	28	28
70% Heat Rate	BTU/KWh	10,314	10,668	10,538	10,258	12,155	10,993	10,993	10,993	10,993	10,993	10,993	10,993	10,993
55% Load	MW	194	88	116	182	147	22	22	22	22	22	22	22	22
55% Heat Rate	BTU/KWh	10,418	10,817	10,638	10,268	12,545	11,925	11,925	11,925	11,925	11,925	11,925	11,925	11,925
Minimum Load	MW	133	80	105	200	144	10	10	10	10	10	10	10	10
Minimum Load Heat Rate	BTU/KWh	10,991	10,909	10,712	10,246	12,593	17,293	17,293	17,293	17,293	17,293	17,293	17,293	17,293

Note: JB = Jim Bridger
NT = Naughton
WY = Wyodak
WV = West Valley

HOURLY OPERATING MARGIN

The Hourly Operating Margin, after unit forced outage, was based on WECC Operating Reserves to cover Contingency Reserves and Regulating Reserves.

- Regulating Reserves: 175 MW to control frequency to ACE tolerance
- Contingency Reserves: 5% of control area demand carried by hydrogeneration and 7% of the control area demand carried by thermal units.

HYDROGENERATION PLANT OPERATING LIFE

Table C.15 Hydrogeneration Plant Life

Power Supply Estimated Plant Lives Hydro Resources

Plant	PacifiCorp Share Net Rating (MW)	Commercial Date	Current Age of Unit	Weighted Average Age of Plant	Power Supply Recommended Life	Power Supply Recommedation Year Ending Life	Years Remaining from 2002
Ashton	6.85	1923	79	79	105	2028	26
St. Anthony	0.50	1915	87	87	113	2028	26
Cutler	30.00	1927	75	75	97	2024	22
Cove	7.50	1917	85	85	114	2031	29
Grace	33.00	1923	79	79	108	2031	29
Onieda	30.00	1915	87	87	116	2031	29
Soda	14.00	1924	78	78	107	2031	29
Upper American Fork	0.95	1964	38	38	66	2008	6
Pioneer	5.00	1914	88	88	116	2030	28
Stairs	1.00	1914	88	88	111	2025	23
Weber	3.85	1949	53	53	71	2020	18
Big Fork	4.15	1924	78	78	107	2031	29
Wallowa Falls	1.10	1921	81	81	95	2016	14
Powerdale	6.00	1923	79	79	95	2018	16
Condit	9.60	1913	89	89	91	2006	4
Merwin	136.00	1932	70	70	104	2036	34
Swift-1	240.00	1958	44	44	78	2036	34
Yale	134.00	1963	39	39	73	2036	34
Lemolo-1	29.00	1955	47	47	85	2040	38
Lemolo-2	33.00	1956	46	46	84	2040	38
Clearwater-1	15.00	1953	49	49	87	2040	38
Clearwater-2	26.00	1953	49	49	87	2040	38
Tokatee	42.50	1939	63	63	101	2040	38
Fish Creek	11.00	1952	50	50	88	2040	38
Soda Springs	11.00	1952	50	50	88	2040	38
Slide Creek	18.00	1951	51	51	89	2040	38
Prospect-1, 2 & 4	36.76	1912	90	90	123	2035	33
Prospect-3	7.20	1932	70	70	87	2019	17
East Side	3.20	1924	78	78	82	2010	8
West Side	0.60	1908	94	94	98	2010	8
JC Boyle	80.00	1958	44	44	78	2036	34
Iron Gate	18.00	1962	40	40	74	2036	34
Copco-1	20.00	1918	84	84	118	2036	34
Copco-2	27.00	1925	77	77	100	2025	23
Fall Creek	2.20	1908	94	94	98	2006	4
Paris	0.70	1910	92	92	105	2015	13
Last Chance	1.70	1984	18	18	41	2025	23
Upper Beaver	2.52	1907	95	95	123	2030	28
Granite	2.00	1896	106	106	134	2030	28
Snake Creek	1.18	1910	92	92	110	2020	18
Fountain Green	0.16	1922	80	80	88	2010	8
Gunlock	0.75	1917	85	85	103	2020	18
Veyo	0.50	1920	82	82	100	2020	18
Sand Cove	0.80	1920	82	82	100	2020	18
Viva Naughton	0.74	1986	16	16	54	2040	38
Cline Falls	1.00	1943	59	59	62	2005	3
Bend	1.11	1913	89	89	92	2005	3
Skookumchuck	1.00	1990	12	12	58	2048	46
Naches Drop	1.40	1915	87	87	91	2006	4
Naches	6.37	1909	93	93	97	2006	4
Eagle Point	2.80	1957	45	45	53	2010	8
	1,068.69						
The following are associated with and support PacifiCorp's Hydro facilities, but do not have generation							
Keno Regulating Dam						2036	34
Klamath Lake Reservoir						2036	34
Lifton						2048	46
North Umpqua General						2040	38
The following is operated by PacifiCorp, but is owned by others							
Olmsted	10.30					2016	14

Power Supply Assumptions:

Plant life is based on license or future licence expiration date

Plant life is based on engineering estimate of remaining civil/structural life

Plant life is based on engineering estimate of remaining electrical/mechanical life

Weighted Average Age of All Plants =	57.4
Reference Year	2002

HYDROGENERATION RELICENSING IMPACTS ON GENERATION

Assumption: All Hydrogeneration plants are relicensed

Table C.16 Hydrogeneration Relicensing Impacts on Generation

Estimate of Hydro relicensing impacts on Energy Generation

Estimated monthly reduction in Hydro Generation (MWh)									
TOTAL	2003	2004	2005	2006	2007	2008	2009	2010	2011
31 Jan	1,430	2,201	2,201	10,203	12,579	28,447	28,447	37,912	40,239
28 Feb	1,292	1,988	1,988	9,404	11,781	25,445	25,445	34,910	37,012
31 Mar	1,430	2,201	2,201	9,817	12,193	25,767	25,767	35,232	37,450
30 Apr	1,658	2,550	2,550	11,894	14,271	24,648	24,648	34,113	36,618
31 May	1,065	1,638	1,638	9,050	11,426	21,759	21,759	31,224	32,926
30 Jun	1,195	1,839	1,839	11,599	13,976	21,899	21,899	31,364	33,785
31 Jul	1,653	2,543	2,543	13,147	15,523	20,153	20,153	29,618	32,776
31 Aug	1,838	2,828	2,828	12,165	14,541	17,708	17,708	27,173	30,054
30 Sep	1,779	2,737	2,737	11,474	13,851	18,680	18,680	28,145	30,832
31 Oct	1,838	2,828	2,828	12,253	14,630	21,960	21,960	31,425	34,331
30 Nov	1,384	2,130	2,130	11,431	13,808	26,897	26,897	36,362	39,036
31 Dec	1,430	2,201	2,201	10,203	12,579	29,249	29,249	38,715	41,042
Estimated monthly reduction in Hydro Generation (MWh)									
TOTAL	2003	2004	2005	2006	2007	2008	2009	2010	2011
31 Jan	1.9	3.0	3.0	13.7	16.9	38.2	38.2	51.0	54.1
28 Feb	1.9	3.0	3.0	14.0	17.5	37.9	37.9	51.9	55.1
31 Mar	1.9	3.0	3.0	13.2	16.4	34.6	34.6	47.4	50.3
30 Apr	2.3	3.5	3.5	16.5	19.8	34.2	34.2	47.4	50.9
31 May	1.4	2.2	2.2	12.2	15.4	29.2	29.2	42.0	44.3
30 Jun	1.7	2.6	2.6	16.1	19.4	30.4	30.4	43.6	46.9
31 Jul	2.2	3.4	3.4	17.7	20.9	27.1	27.1	39.8	44.1
31 Aug	2.5	3.8	3.8	16.4	19.5	23.8	23.8	36.5	40.4
30 Sep	2.5	3.8	3.8	15.9	19.2	25.9	25.9	39.1	42.8
31 Oct	2.5	3.8	3.8	16.5	19.7	29.5	29.5	42.2	46.1
30 Nov	1.9	3.0	3.0	15.9	19.2	37.4	37.4	50.5	54.2
31 Dec	1.9	3.0	3.0	13.7	16.9	39.3	39.3	52.0	55.2

Source: Hydro licensing department 5/22/02

As more information is known regarding project licensing efforts, these numbers can be updated.

INDUSTRIAL CUSTOMERS

PacifiCorp assumes for purpose of this IRP that all its industrial customers will remain retail customers for the life of the plan.

INFLATION

Where price forecasts were not established by external sources, the simulations were performed with an inflation rate of 2.5%, consistent with the PacifiCorp Business Planning assumptions.

MARKET DEPTH AND LIQUIDITY

PaciCorp's market access is capped as follows:

- 250 MW at COB
- 250 MW at Mid-Columbia, and
- 500 MW at Palo Verde

Such limits help constrain the model from impractical dispatch decisions and appear consistent with historical practice. All market transactions outside of existing long-term contracts are subject to this limitation. See "Critical Assumptions" in Appendix J for more details.

PLANNING MARGIN

The Planning Margin selected is 15% of the annual peak hour when the loads plus long-term firm sales minus long-term firm purchases result in the largest requirement on the system. This target reserve level assumed to provide sufficient future resources to cover forced outages, provide operating reserves regulatory margin, and demand growth uncertainty.

RENEWABLE ASSUMPTIONS

The production tax credit (PTC) is modeled as $18/MWh but only for the first ten years of production for a wind plant. This breakdown of costs was done over a 20-year life of the plant so the present value of the PTC is more like $12.36/MWh. The green tag value was also impacted since we assume it only has value for the first 5 years of the plant life.

Table C.17 Calculation of the Federal Renewable Portfolio Standard (RPS) Model

Year	OR, WA, UT Load GWHs	TOTAL PAC Load GWHs	Avg WY Hydro Gen GWHs	BASE - SENATE RPS %	MWhs	Mwa
2002	49,818	59,803	4,757			
2003	50,663	60,717	4,739			
2004	51,797	61,975	4,730			
2005	52,990	63,323	4,703	1.00	173,110	20
2006	54,165	64,692	4,596	1.60	545,998	62
2007	54,934	65,657	4,596	2.20	925,352	106
2008	51,786	62,721	4,493	2.80	1,209,921	138
2009	52,807	63,950	4,493	3.40	1,598,619	182
2010	53,878	65,213	4,380	4.00	2,007,967	229
2011	54,990	66,520	4,350	4.60	2,432,010	278
2012	56,039	67,781	4,350	5.20	2,868,149	327
2013	57,559	69,531	4,350	5.80	3,347,782	382
2014	58,918	71,059	4,350	6.40	3,834,206	438
2015	60,287	72,607	4,350	7.00	4,340,367	495
2016	61,673	74,195	4,350	7.60	4,868,143	556
2017	63,184	75,891	4,350	8.20	5,423,832	619
2018	64,861	77,775	4,350	8.80	6,016,416	687
2019	66,608	79,769	4,350	9.40	6,641,949	758
2020	68,031	81,454	4,350	10.00	7,260,510	829

*Estimate of current contracts and owned geothermal, biomass and wind for 2002 = 409 GWHs

PAC RPS includes 75% hydro and 50% other renewables reduction in base calculation
SENATE RPS includes 100% hydro and other renewables reduction in base calculation
SENATE BASE MWHS = (PAC total load - 100% Hydro Gen- 100% Existing Renewables)
SENATE BASE MWa = ((Base MWhs * RPS %) - 100% Existing Renewable)/8760
SENATE BASE CY 2013: 382 MWa or Capacity (382X3) = 1146 MW

SPOT MARKET PURCHASES (LIMIT TO 5% OF THE HOURS IN ANY YEAR)

The decision was made to limit expected spot purchases to 5% or less of each year's hours based on input from the Public Input Process. Original requests were for PacifiCorp to build to cover 100% of its position. PacifiCorp believes building or buying to cover 100% of its position (the needle peak hour) is excessively conservative; EFOR alone can account for more than 5% for the duration.

While initially a product of the Public Input Process, the 5% limitation was also observed to mitigate the risk associated with power price volatility. Power price volatility can be considerable. It is true that minimization of power price risk favors being long power more often than being short since prices are unbounded on the upside, but cannot be negative under current market rules. However a long position or even a 100% coverage position require either more owned or controlled capacity or a large amount of both shaped purchases or call optionality. These positions can be structured and can be cost effective, but they are a very fine level of detail to be shown in an IRP. The 5% limitation is not inconsistent with a prudent spot market exposure which PacifiCorp is now successfully managing. Recent market experience supports this. Filling the 5% short with peak hour block purchases will create shoulder hour length that will have a high probability of being surplus. This relatively small short position (approximately 5%) is favored on the basis of prudent commodity risk management.

STUDY PERIOD

The study period covers a 20-year period beginning April 1, 2003 and ending March 31, 2023, and market simulations were performed for all years.

SUPPLY SIDE RESOURCES

Table C.18 Potential Supply Side Resources

Supply Side Resources												
	Fuel	Installation Location	Technology	Plant Lead Time - Months.	Capacity MW	Maximum Capacity Addition per Site	Capital Cost in $/kW (Average)	Annual Heat Rate HHV	Maint. Outage Rate (1-EAF-EFOR)	Equivalent Forced Outage Rate (EFOR)	Fuel Cost $/mmBtu	Var. O&M $/MWh	Fixed O&M in $/kW-yr
East Side Options (4500'):													
Coal													
Extend Existing Carbon Units 10 years	Utah Coal	Utah	PC-Sub	0	175	0	$42	11,350	4.3%	4.7%	$0.61	$0.25	$54.50
Hunter 4 - PC	Utah Coal	Utah	PC-Sub	48	575	575	$1,389	9,483	5.0%	4.0%	$0.72	$0.73	$27.39
Utah Greenfield PC	Utah Coal	Utah	PC-Sub (2x500)	60	575	1,150	$1,431	9,483	5.0%	4.0%	$1.00	$0.73	$33.94
Utah Greenfield IGCC	Utah Coal	Utah	IGCC - 7FA (2x1)	66	370	740	$1,797	8,311	15.0%	10.0%	$1.00	$1.83	$25.94
Wyoming Greenfield PC	PRB	Wyoming	PC-Sub - PRB	66	575	1,150	$1,501	9,483	5.0%	4.0%	$0.84	$0.73	$33.94
Natural Gas													
Microturbines	Nat. Gas	Utah	Capstone	12	0.020	0.204	$2,312	14,321	1.0%	1.0%	Nat. Gas	$7.93	$433.25
Fuel Cells	Nat. Gas	Utah	SOFC (Westinghouse)	12	0.225	2	$1,500	5,688	1.0%	1.0%	Nat. Gas	$2.13	$53.78
Extend Existing Gadsby Units 10 years	Nat. Gas	Utah	Steam Boilers	0	235	235	$9	12,950	1.0%	3.7%	Nat. Gas	$0.10	$27.61
Utah CHP (Cogen. - CT)	Nat. Gas	Utah	7FA (1x1) - 100K Steam	41	190	190	$1,025	7,136	4.1%	4.6%	Nat. Gas	$1.94	$13.31
Utah CHP (Non CT)	Nat. Gas	Utah	Topping Turbine	24	25	50	$659	5,305	5.0%	10.0%	Nat. Gas	$0.15	$25.69
Greenfield SCCT Aero	Nat. Gas	Utah	SCCT - 2 - LM6000	12	80	400	$844	10,233	0.0%	10.2%	Nat. Gas	$3.90	$11.45
Greenfield SCCT Frame	Nat. Gas	Utah	SCCT - 1 - 501D5	24	100	400	$539	12,176	0.0%	10.2%	Nat. Gas	$3.14	$11.23
Brownfield SCCT Frame (Mona)	Nat. Gas	Utah	SCCT - 1 - 501D5	24	100	400	$458	12,176	0.0%	10.2%	Nat. Gas	$3.14	$11.23
Gadsby Repowering (1x1)	Nat. Gas	Utah	CCCT - 7FA (1x1)	41	210	210	$927	7,235	4.1%	4.6%	Nat. Gas	$1.94	$13.31
Gadsby Repowering Duct Firing (1x1)	Nat. Gas	Utah	2-7FA Duct Firing	41	30	30	$253	11,998	4.1%	4.6%	Nat. Gas	$0.00	$3.80
Gadsby Repowering (2x1)	Nat. Gas	Utah	CCCT - 7FA (2x1)	41	440	440	$670	7,074	4.1%	4.6%	Nat. Gas	$1.77	$7.83
Gadsby Repowering Duct Firing (2x1)	Nat. Gas	Utah	2-7FA Duct Firing	41	70	70	$205	9,219	4.1%	4.6%	Nat. Gas	$0.00	$3.80
Greenfield CCCT 2 - 1x1 (Intermediate Load)	Nat. Gas	Utah	CCCT - 7FA (1x1)	48	420	840	$770	7,235	4.1%	4.6%	Nat. Gas	$1.94	$8.29
Greenfield CCCT Duct Firing 2 - 1x1	Nat. Gas	Utah	2-7FA Duct Firing	48	60	120	$253	11,998	4.1%	4.6%	Nat. Gas	$0.00	$3.80
Greenfield CCCT 2x1	Nat. Gas	Utah	CCCT - 7FA (2x1)	48	440	880	$706	7,074	4.1%	4.6%	Nat. Gas	$1.77	$7.83
Greenfield CCCT Duct Firing 2x1	Nat. Gas	Utah	7FA Duct Firing	48	70	140	$205	9,219	4.1%	4.6%	Nat. Gas	$0.00	$3.08
Greenfield CCCT "G" 2x1	Nat. Gas	Utah	CCCT - 501G (2x1)	48	615	1,230	$650	6,945	4.1%	4.6%	Nat. Gas	$1.65	$6.09
Greenfield CCCT "G" Duct Firing 2x1	Nat. Gas	Utah	501G Duct Firing	48	110	220	$229	8,554	4.1%	4.6%	Nat. Gas	$0.00	$3.43
Other - Renewables													
Wind - Wyoming (36% CF)	n/a	Wyoming	1650 kW machines	12	50	200	$1,000	n/a	n/a	n/a	n/a	$0.00	$22.65
Wind - Utah	n/a	Utah	1650 kW machines	12	50	200	$1,000	n/a	n/a	n/a	n/a	$0.00	$22.65
Blundell Upgrade	Geothermal	Utah	K-ST	24	50	50	$1,880	10,000	4.1%	0.9%	$18/MWh	$0.10	$16.00
Pumped Storage	Water/coal	Nevada	Pumped Hydro	36	200	400	$850	13,924	n/a	n/a	$1.00	$0.51	$10.00
Solar	Solar	Utah	Thermal (Solar II)	48	200	200	$5.028	n/a	n/a	n/a	n/a	$0.20	$41.18

Technology Code:	PC-Sub	Pulverized Coal - Subcritical
	IGCC	Intergrated Gasification Combined Cycle (Clean Coal Tech.)
	SCCT	Simple Cycle Combustion Turbine
	CCCT	Combined Cycle Combustion Turbine
	CCCT	Repower Combined Cycle
	K-ST	Kalina based Steam Turbine
	Cogen	Cogeneration
	Elevation Correction Factor for east to west	

Table C.18 Potential Supply Side Resources (Continued)

	Supply Side Resources								
					Emissions				
	Minimum Load as a percent of Capacity	Minimum Time to Full Load in Minutes (Warm Start)	Average Down Time in Minutes	Cost per Startup	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu	Comments
East Side Options (4500'):									
Coal									
Extend Existing Carbon Units 10 years	25%	180	720	$1,151	0.640	0.420	2.2	204	Startup Costs based on Unit 2 - assumes no new emission controls
Hunter 4 - PC	25%	240	720	$3,755	0.030	0.080	0.6	204	Costs based on Hunter 4 Consortium Proposal
Utah Greenfield PC	25%	240	720	$3,755	0.030	0.080	0.6	204	Costs based on modified Hunter 4 Consortium Proposal
Utah Greenfield IGCC	25%	360	720	$2,403	0.030	0.050	0.6	204	Assume Technology not available for decision till 2006
Wyoming Greenfield PC	25%	240	720	$3,755	0.030	0.080	1.5	204	Costs based on modified Hunter 4 Consortium Proposal
Natural Gas									
Microturbines	25%	5	240	$462	0.00147	0.0080	0.255	118	Base on RAMPP6 - no escalation
Fuel Cells	25%	30	240	$462	0.00147	0.0039	0.255	118	Based on Westinghouse CHP250 System - Available post 2005
Extend Existing Gadsby Units 10 years	25%	120	720	$462	0.00147	0.080	0.255	118	Base Startup and EFOR Values on Unit 3 (20010921)
Utah CHP (Cogen. - CT)	25%	25	60	$1,095	0.00147	0.0080	0.255	118	Use new 7 FA CT values and a 100,000 lb/hr steam load
Utah CHP (Non CT)	25%	120	480	$115	0.00147	0.0800	0.255	118	Base on RAMPP6 with no escalation (50 MW during planning horizon)
Greenfield SCCT Aero	25%	10	30	$571	0.00147	0.0080	0.255	118	Costs assume a minimum of two machines (HR assumes compressor)
Greenfield SCCT Frame	25%	25	60	$714	0.00147	0.0080	0.255	118	Costs based on two machines (HR assumes compressor)
Brownfield SCCT Frame (Mona)	25%	25	60	$714	0.00147	0.0483	0.255	118	DLN NOx control only (Maximum CF of 20%)
Gadsby Repowering (1x1)	25%	240	480	1,210	0.00147	0.0088	0.255	118	
Gadsby Repowering Duct Firing (1x1)	25%	20	0	$0	0.00147	0.0299	0.255	118	Only Available with Gadsby Repower
Gadsby Repowering (2x1)	25%	240	480	$2,536	0.00147	0.0088	0.255	118	
Gadsby Repowering Duct Firing (2x1)	25%	20	0	$0	0.00147	0.0299	0.255	118	Only Available with Gadsby Repower
Greenfield CCCT 2 - 1x1 (Intermediate Load)	25%	240	480	$2,421	0.00147	0.0088	0.255	118	Assume best CCCT option for Capacity Factors between 20% and 65%
Greenfield CCCT Duct Firing 2 - 1x1	25%	20	0	$0	0.00147	0.0299	0.255	118	Only Available with CCCT
Greenfield CCCT 2x1	25%	240	480	$2,536	0.00147	0.0088	0.255	118	
Greenfield CCCT Duct Firing 2x1	25%	20	0	$0	0.00147	0.0299	0.255	118	Only Available with CCCT
Greenfield CCCT "G" 2x1	25%	240	480	$3,544	0.00147	0.0088	0.255	118	Not available till 2006
Greenfield CCCT "G" Duct Firing 2x1	25%	20	0	$0	0.00147	0.0299	0.255	118	Only Available with CCCT
Other - Renewables									
Wind - Wyoming (36% CF)	5%	10	0	$0	0.00000	0.0000	0.000	0	Based on 8/27/02 NWPC work - not including tax credit or dispatch cost
Wind - Utah	5%	10	0	$0	0.00000	0.0000	0.000	0	Based on Developers numbers - Utah site not identified
Blundell Upgrade	25%	60	240	n/a	0.00000	0.0000	0.000	0	Mac Crosby 04/09 (Steam cost estimated 25% less than current $24/MWh)
Pumped Storage	20%	15	480	$0	0.10000	0.4000	3.000	204	Capacity Factor limited to 17% - cost based on system average coal
Solar	25%	60	720	$0	0.00000	0.0000	0.000	0	Based on lowest pure Solar option from RAMPP6 (Solar II - 63% CF)

Technology Code:

PC-Sub	Pulverized Coal - Subcritical
IGCC	Intergrated Gasification Combined Cycle (Clean Coal Tech.)
SCCT	Simple Cycle Combustion Turbine
CCCT	Combined Cycle Combustion Turbine
CCCT	Repower Combined Cycle
K-ST	Kalina based Steam Turbine
Cogen	Cogeneration

Elevation Correction Factor for east to west

Table C.18 Potential Supply Side Resources (Continued)

Supply Side Resources													
	Fuel	Installation Location	Technology	Plant Lead Time - Months.	Capacity MW	Maximum Capacity Addition per Site	Capital Cost in $/kW (Average)	Annual Heat Rate HHV	Maint. Outage Rate (1-EAF-EFOR)	Equivalent Forced Outage Rate (EFOR)	Fuel Cost $/mmBtu	Var. O&M $/MWh	Fixed O&M in $/kW-yr
West Side Options (1500')													
Natural Gas													
Microturbines	Nat. Gas	Northwest	Capstone	12	0.023	0.228	$2,069	14,321	1.0%	1.0%	Nat. Gas	$2.13	$48.11
Fuel Cells	Nat. Gas	Northwest	SOFC (Westinghouse)	12	0.225	2	$1,500	5,688	1.0%	1.0%	Nat. Gas	$2.13	$53.78
West Side CHP (Cogen. CT)	Nat. Gas	Northwest	501D5 - 200,000 lb/hr	41	212	212	$917	7,136	4.1%	4.6%	Nat. Gas	$1.94	$13.31
West Side CHP (Non CT)	Nat. Gas	Northwest	Topping Turbine	24	25	50	659	5,305	5.0%	10.0%	Nat. Gas	$0.15	$25.69
Greenfield SCCT Aero	Nat. Gas	Northwest	SCCT - 2 - LM6000	12	90	450	$755	10,233	0.0%	10.2%	Nat. Gas	$3.55	$10.24
Greenfield SCCT Frame	Nat. Gas	Northwest	SCCT - 1 - 501D5	24	115	460	$482	12,176	0.0%	10.2%	Nat. Gas	$2.86	$10.05
Greenfield CCCT 2 - 1x1 (Intermediate Load)	Nat. Gas	Northwest	CCCT - 7FA (1x1)	48	470	940	$689	7,235	4.1%	4.6%	Nat. Gas	$1.76	$7.42
Greenfield 2 - 1x1 Duct Firing	Nat. Gas	Northwest	2-7FA Duct Firing	48	70	140	$227	11,998	4.1%	4.6%	Nat. Gas	$0.00	$3.40
Greenfield CCCT 2x1	Nat. Gas	Northwest	CCCT - 7FA (2x1)	48	490	980	$631	7,074	4.1%	4.6%	Nat. Gas	$1.61	$7.00
Greenfield CCCT Duct Firing 2x1	Nat. Gas	Northwest	Duct Firing - 7FA	48	80	160	$184	9,219	4.1%	4.6%	Nat. Gas	$0.00	$2.75
Greenfield CCCT "G" 2x1	Nat. Gas	Northwest	CCCT - 501G (2x1)	48	690	1,380	$581	6,945	4.1%	4.6%	Nat. Gas	$1.50	$5.44
Greenfield CCCT "G" Duct Firing 2x1	Nat. Gas	Northwest	501G Duct Firing	48	120	240	$205	8,554	4.1%	4.6%	Nat. Gas	$0.00	$3.07
Other - Renewables													
West Side Wind (30% CF)	n/a	Northwest	Stateline Econ.	12	50	300	$1,000	n/a	n/a	5.0%	n/a	$0.00	$22.65

Technology Code: PC-Sub Pulverized Coal - Subcritical
IGCC Intergrated Gasification Combined Cycle (Clean Coal Tech.)
SCCT Simple Cycle Combustion Turbine
CCCT Combined Cycle Combustion Turbine
CCCT Repower Combined Cycle
K-ST Kalina based Steam Turbine
Cogen Cogeneration
Elevation Correction Factor for east to west

Table C.18 Potential Supply Side Resources (Continued)

Supply Side Resources									
					Emissions				
	Minimum Load as a percent of Capacity	Minimum Time to Full Load in Minutes (Warm Start)	Average Down Time in Minutes	Cost per Startup	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu	Comments
West Side Options (1500')									
Natural Gas									
Microturbines	25%	5	240	$462	0.00147	0.0800	0.255	118	Base on RAMPP6 - no escalation
Fuel Cells	25%	30	240	$0	0.00147	0.0039	0.255	118	Base on RAMPP6 - no escalation
West Side CHP (Cogen. CT)	25%	25	60	$1,095	0.00147	0.0080	0.255	118	Use new CT values and a 100,000 lb/hr steam load
West Side CHP (Non CT)	25%	120	480	$115	0.00147	0.08000	0.255	118	Base on RAMPP6 with no escalation (50 MW during planning horizon)
Greenfield SCCT Aero	25%	10	30	$643	0.00147	0.00805	0.255	118	Based on East numbers adjusted by elevation factor
Greenfield SCCT Frame	25%	25	60	$821	0.00147	0.00805	0.255	118	Based on East numbers adjusted by elevation factor
Greenfield CCCT 2 - 1x1 (Intermediate Load)	25.0%	240	480	$2,421	0.00147	0.0088	0.255	118	Assume best CCCT option for Capacity Factors between 20% and 65%
Greenfield 2 - 1x1 Duct Firing	25.0%	20	0	$0	0.00147	0.0299	0.255	118	Based on Utah numbers adjusted by elevation factor
Greenfield CCCT 2x1	25.0%	240	480	$2,536	0.00147	0.0088	0.255	118	Based on Utah numbers adjusted by elevation factor
Greenfield CCCT Duct Firing 2x1	25.0%	20	0	$0	0.00147	0.0299	0.255	118	Based on Utah numbers adjusted by elevation factor
Greenfield CCCT "G" 2x1	25.0%	240	480	$3,544	0.00147	0.0088	0.255	118	Based on Utah numbers adjusted by elevation factor - not available till 2006
Greenfield CCCT "G" Duct Firing 2x1	25.0%	20	0	$0	0.00147	0.0299	0.255	118	Based on Utah numbers adjusted by elevation factor
Other - Renewables									
West Side Wind (30% CF)	5%	10	0	$0	0.00000	0.000	0.0	0	Base on RAMPP6 - Capacity Factor of 37%

Technology Code:
PC-Sub Pulverized Coal - Subcritical
IGCC Intergrated Gasification Combined Cycle (Clean Coal Tech.)
SCCT Simple Cycle Combustion Turbine
CCCT Combined Cycle Combustion Turbine
CCCT Repower Combined Cycle
K-ST Kalina based Steam Turbine
Cogen Cogeneration
Elevation Correction Factor for east to west

Table C.19 Potential Supply Side Resources

(Generated in response to the draft IRP Questions)

Potential Resource Cost - Sorted by First Year of Real Levelized Total Resource Costs in 2002 Dollars

Page 1 of 2

Description	Unit Size MW Unit Size	MWs Avail.	1st Year Avail	Approximate Location	Reserve Margin Contribution	Forced Outage Rate	Maint. Outage Rate	Annual Heat Rate BTU/kWh	Fuel Type	Emissions SO2 lbs/MMBTU (Hg: lbs/Tbtu)	NOx	Hg	CO2	Capital Cost-$/kW Unit Cost	Trans-mission
East Side															
Wind - Wyoming near Evanston (36% CF)	50	200	2004	Western Wyoming	-	n/a	n/a	n/a	0.0	-	-	-	-	1,000	80
Blundell Upgrade	50	50	2006	Central Utah	100%	0.9%	4.1%	10,000	0.0	-	-	-	-	1,880	20
Hunter 4 - Pulverized Coal	575	575	2007	Central Utah	100%	4.0%	5.0%	9,483	190H	0.030	0.080	0.600	203.6	1,389	193
Extend Carbon 10 years - SO2/50% Hg Controls Added	175	-	2011	Central Utah	100%	4.7%	4.3%	11,350	190H	0.096	0.252	1.110	203.6	251	-
Utah Greenfield Pulverized Coal	575	1,150	2010	Central Utah	100%	4.0%	5.0%	9,483	190H	0.030	0.080	0.600	203.6	1,431	193
Utah CHP (Non CT - No Projects Identified)	25	50	2006	Utah	100%	10.0%	5.0%	5,305	COALW1	0.001	0.080	0.255	117.6	659	-
Wind - Utah (32%)	50	200	2004	West Central Utah	-	n/a	n/a	n/a	0.0	-	-	-	-	1,000	100
Greenfield CCCT "G" 2x1	615	1,230	2010	Central Utah	100%	4.6%	4.1%	6,945	190H	0.001	0.009	0.255	117.6	650	41
Utah Greenfield IGCC	370	740	2012	Hunter Plant	100%	10.0%	15.0%	8,311	190H	0.030	0.050	0.600	203.6	1,797	150
Gadsby Repowering - 2x1	440	440	2007	Wasatch Front	100%	4.6%	4.1%	7,074	0.0	0.001	0.009	0.255	117.6	670	41
Greenfield CCCT 2x1	440	880	2007	Central Utah	100%	4.6%	4.1%	7,074	0.0	0.001	0.009	0.255	117.6	706	62
Wyoming Greenfield Pulverized Coal	575	1,150	2009	Near Jim Bridger	100%	4.0%	5.0%	9,483	190H	0.030	0.080	1.500	203.6	1,501	555
Greenfield CCCT 2 - 1x1 (Intermediate Load)	420	840	2007	Utah	100%	4.6%	4.1%	7,235	GEOTH	0.001	0.009	0.255	117.6	770	66
Utah CHP (Cogen. - CT)	190	190	2007	Utah	100%	4.6%	4.1%	7,136	COALU1	0.001	0.008	0.255	117.6	1,025	-
Gadsby Repowering (1x1)	210	210	2007	Wasatch Front	100%	4.6%	4.1%	7 235	COALU3	0.001	0.009	0.255	117.6	927	57
Fuel Cells	0.23	2.25	2010	Utah	100%	1.0%	1.0%	5,688	COALW1	0.001	0.004	0.255	117.6	1,500	-
Wind - Wyoming near Foote Creek (36% CF)	50	200	2004	Eastern Wyoming	-	n/a	n/a	n/a	0.0	-	-	-	-	1,000	855
Greenfield CCCT "G" Duct Firing 2x1	110	220	2010	Central Utah	100%	4.6%	4.1%	8,554	190H	0.001	0.030	0.255	117.6	229	-
Greenfield CCCT Duct Firing 2x1	70	140	2007	Central Utah	100%	4.6%	4.1%	9,219		0.001	0.030	0.255	117.6	205	-
Gadsby Repowering Duct Firing (2x1)	70	70	2007	Wasatch Front	100%	4.6%	4.1%	9,219	0.0	0.001	0.030	0.255	117.6	205	-
Solar	200	200	2012	Southern Utah	67%	n/a	n/a	n/a	0.0	-	-	-	-	5,028	30
Gadsby Repowering Duct Firing (1x1)	30	30	2007	Wasatch Front	100%	4.6%	4.1%	11,998		0.001	0.030	0.255	117.6	253	-
Greenfield CCCT Duct Firing 2 - 1x1	60	120	2007	Central Utah	100%	4.6%	4.1%	11,998	GEOTH	0.001	0.030	0.255	117.6	253	-
Extend Existing Gadsby Units 10 years	235	235	2008	Wasatch Front	100%	3.7%	1.0%	12 950	COALW2	0.001	0.080	0.255	117.6	9	-
Pumped Storage	200	400	2006	Southern Nevada	100%	n/a	n/a	13,924	0.0	0.100	0.400	3.000	203.6	850	-
Brownfield SCCT Frame (Mona)	100	400	2006	Central Utah	100%	10.2%	0.0%	12,176	COALU2	0.001	0.048	0.255	117.6	458	15
Greenfield SCCT Frame	100	400	2006	Central Utah	100%	10.2%	0.0%	12,176	COALU2	0.001	0.008	0.255	117.6	539	15
Greenfield SCCT Aero	80	400	2006	Central Utah	100%	10.2%	0.0%	10,233	COALW2	0.001	0.008	0.255	117.6	844	15
Microturbines	0.02	0.20	2006	Utah	100%	1.0%	1.0%	14,321	COALU1	0.001	0.008	0.255	117.6	2 312	-
West Side															
West Side CHP (Non CT)	25	50	2006	Northwest	100%	10.0%	5.0%	5,305		0.001	0.080	0.255	117.6	659	-
West Side Wind (30% CF)	50	300	2004	Northwest	-	n/a	n/a	n/a		-	-	-	-	1,000	67
Greenfield CCCT "G" 2x1	690	1,380	2007	Northwest	100%	4.6%	4.1%	6,945		0.001	0.009	0.255	117.6	581	62
Greenfield CCCT 2x1	490	980	2007	Northwest	100%	4.6%	4.1%	7,074		0.001	0.009	0.255	117.6	631	66
Greenfield CCCT 2 - 1x1 (Intermediate Load)	470	940	2007	Northwest	100%	4.6%	4.1%	7 235		0.001	0.009	0.255	117.6	689	69
West Side CHP (Cogen. CT)	212	212	2007	Northwest	100%	4.6%	4.1%	7,136		0.001	0.008	0.255	117.6	917	-
Fuel Cells	0	2	2010	Northwest	100%	1.0%	1.0%	5,688		0.001	0.004	0.255	117.6	1,500	-
Greenfield CCCT "G" Duct Firing 2x1	120	240	2007	Northwest	100%	4.6%	4.1%	8,554		0.001	0.030	0.255	117.6	205	-
Greenfield CCCT Duct Firing 2x1	80	160	2007	Northwest	100%	4.6%	4.1%	9,219		0.001	0.030	0.255	117.6	184	-
Greenfield 2 - 1x1 Duct Firing	70	140	2007	Northwest	100%	4.6%	4.1%	11,998		0.001	0.030	0.255	117.6	227	-
Greenfield SCCT Frame	115	460	2007	Northwest	100%	10.2%	0.0%	12,176		0.001	0.008	0.255	117.6	482	35
Greenfield SCCT Aero	90	450	2007	Northwest	100%	10.2%	0.0%	10,233		0.001	0.008	0.255	117.6	755	36
Microturbines	0.02	0.23	2006	Northwest	100%	1.0%	1.0%	14,321		0.001	0.080	0.255	117.6	2,069	-

Table C.20 Potential Supply Side Resources

(Generated in response to the draft IRP Questions)
Potential Resource Sorted by Total Resource Costs

	Capital Cost$/kW			Fixed Cost				Convert to Mills				Variable Costs mills/kWh					Total
	Total	Payment	Annual Pmt	Fixed O&M$/kW-Yr			Ttl Fixed	Expected	Ttl Fixed	Levelized Fuel							Resource
Description	Cap Cost	Factor	$/kW-Yr	O&M	Other	Total	$/kW-Yr	Utilization	Mills/kWh	c/mmBtu	Mills/kWh	O&M	Fuel/Other	Total	Tax Credits	Env	Cost
East Side																	
Wind - Wyoming near Evanston (36% CF)	1,080	9.59%	103.57	22.65	0.03	22.68	126.25	36%	40.03	-	-	0.00	5.50	-	(11.71)	-	33.82
Blundell Upgrade	1,900	8.84%	167.96	16.00	2.00	18.00	185.96	95%	22.35	200.00	20.00	0.10	-	-	(7.58)	-	34.87
Hunter 4 - Pulverized Coal	1,582	8.24%	130.35	27.39	5.00	32.39	162.74	91%	20.41	67.32	6.38	0.73	-	0.73		-	27.52
Extend Carbon 10 years - SO2/50% Hg Controls Added	251	16.89%	42.47	66.79	6.46	73.25	115.71	85%	15.54	53.66	6.09	2.63	-	0.15		-	24.26
Utah Greenfield Pulverized Coal	1,624	8.24%	133.85	33.94	5.00	38.94	172.78	91%	21.68	67.32	6.38	0.73	-	0.73		-	28.78
Utah CHP (Non CT - No Projects Identified)	659	9.92%	65.39	25.69	0.20	25.89	91.28	85%	12.26	360.00	19.10	0.15	2.65	2.40		-	34.16
Wind - Utah (32%)	1,100	9.59%	105.49	22.65	0.03	22.68	128.17	32%	45.72	-	-	0.00	5.50	-	(11.71)	-	39.51
Greenfield CCCT "G" 2x1	691	8.61%	59.46	6.09	0.20	6.29	65.74	74%	10.14	360.00	25.00	1.65	3.47	0.84		-	40.27
Utah Greenfield IGCC	1,947	8.24%	160.44	25.94	5.00	30.94	191.38	75%	29.13	67.32	5.59	1.83	-	0.51		-	36.55
Gadsby Repowering - 2x1	712	8.61%	61.27	7.83	0.20	8.03	69.29	74%	10.69	360.00	25.47	1.77	3.54	-		-	41.46
Greenfield CCCT 2x1	767	8.61%	66.07	7.83	0.20	8.03	74.10	74%	11.43	360.00	25.47	1.77	3.54	3.50		-	42.20
Wyoming Greenfield Pulverized Coal	2,056	8.24%	169.38	33.94	5.00	38.94	208.32	91%	26.13	105.00	9.96	0.73	-	0.50		-	36.82
Greenfield CCCT 2 - 1x1 (Intermediate Load)	836	8.61%	71.97	8.29	0.20	8.49	80.47	74%	12.41	360.00	26.04	1.94	3.62	2.12		-	44.01
Utah CHP (Cogen. - CT)	1,025	9.92%	101.66	13.31	0.20	13.51	115.17	91%	14.45	360.00	25.69	1.94	3.57	2.40		-	45.64
Gadsby Repowering (1x1)	984	8.61%	84.70	13.31	0.20	13.51	98.21	74%	15.15	360.00	26.04	1.94	3.62	0.51		-	46.75
Fuel Cells	1,500	9.82%	147.30	53.78	5.00	58.78	206.08	98%	24.00	360.00	20.48	2.13	2.84	0.51		-	49.46
Wind - Wyoming near Foote Creek (36% CF)	1,855	9.59%	177.89	22.65	0.03	22.68	200.57	36%	63.60	-	-	0.00	5.50	-	(11.71)	-	57.39
Greenfield CCCT "G" Duct Firing 2x1	229	8.61%	19.72	3.43	0.20	3.63	23.35	12%	22.21	360.00	30.79	0.00	4.28	2.10		-	57.28
Greenfield CCCT Duct Firing 2x1	205	8.61%	17.67	3.08	0.20	3.28	20.95	12%	19.93	360.00	33.19	0.00	4.61			-	57.73
Gadsby Repowering Duct Firing (2x1)	205	8.61%	17.67	3.80	0.20	4.00	21.67	12%	20.62	412.68	38.05	0.00	4.61	-		-	63.27
Solar	5,058	7.44%	376.30	41.18	-	41.18	417.48	67%	71.13	-	-	0.20	-	-		-	71.33
Gadsby Repowering Duct Firing (1x1)	253	8.61%	21.80	3.80	0.20	4.00	25.80	12%	24.55	412.68	49.51	0.00	6.00			-	80.06
Greenfield CCCT Duct Firing 2 - 1x1	253	8.61%	21.80	3.80	0.20	4.00	25.80	12%	24.55	412.68	49.51	0.00	6.00	2.12		-	80.06
Extend Existing Gadsby Units 10 years	-	16.89%	-	27.61	2.29	29.90	29.90	12%	28.45	360.00	46.62	0.10	6.48	0.51		-	81.64
Pumped Storage	850	8.61%	73.19	10.00	2.00	12.00	85.19	17%	57.20	100.00	13.92	0.51	-	-		-	71.64
Brownfield SCCT Frame (Mona)	473	9.59%	45.35	11.23	0.20	11.43	56.78	12%	54.02	412.68	50.25	3.14	6.09	2.40		-	113.49
Greenfield SCCT Frame	554	9.59%	53.12	11.23	0.20	11.43	64.55	12%	61.41	412.68	50.25	3.14	6.09	0.51		-	120.89
Greenfield SCCT Aero	859	9.59%	82.38	11.45	0.20	11.65	94.02	12%	89.44	412.68	42.23	3.90	5.12	2.40		-	140.69
Microturbines	2,312	11.64%	269.14	433.25	-	433.25	702.39	98%	81.82	360.00	51.55	7.93	7.16	0.51		-	148.46
West Side																	
West Side CHP (Non CT)	659	9.92%	65.39	25.69	0.20	25.89	91.28	85%	12.26	362.93	19.25	0.15	2.65			-	34.32
West Side Wind (30% CF)	1,067	9.59%	102.29	22.65	0.03	22.68	124.97	32%	44.58	-	-	0.00	5.50		(11.71)	-	38.37
Greenfield CCCT "G" 2x1	643	8.61%	55.38	5.44	0.20	5.64	61.02	86%	8.10	362.93	25.21	1.50	3.47			-	38.28
Greenfield CCCT 2x1	697	8.61%	60.02	7.00	0.20	7.20	67.22	86%	8.92	362.93	25.67	1.61	3.54			-	39.74
Greenfield CCCT 2 - 1x1 (Intermediate Load)	759	8.61%	65.32	7.42	0.20	7.62	72.94	86%	9.68	362.93	26.28	1.76	3.62			-	41.32
West Side CHP (Cogen. CT)	917	9.92%	90.96	13.31	0.20	13.51	104.47	91%	13.11	362.93	25.90	1.94	3.57			-	44.51
Fuel Cells	1,500	9.82%	147.30	53.78	5.00	58.78	206.08	98%	24.00	362.93	20.64	2.13	2.84			-	49.62
Greenfield CCCT "G" Duct Firing 2x1	205	8.61%	17.64	3.07	0.20	3.27	20.91	23%	10.38	415.61	35.55	0.00	4.28			-	50.21
Greenfield CCCT Duct Firing 2x1	184	8.61%	15.81	2.75	0.20	2.95	18.77	23%	9.31	415.61	38.32	0.00	4.61			-	52.24
Greenfield 2 - 1x1 Duct Firing	227	8.61%	19.51	3.40	0.20	3.60	23.11	23%	11.47	415.61	49.86	0.00	6.00			-	67.33
Greenfield SCCT Frame	517	9.59%	49.58	10.05	0.20	10.25	59.83	23%	29.69	415.61	50.60	2.88	6.09			-	89.25
Greenfield SCCT Aero	791	9.59%	75.83	10.24	0.20	10.44	86.27	23%	42.82	415.61	42.53	3.55	5.12			-	94.02
Microturbines	2,069	11.64%	240.81	387.64	-	387.64	628.45	98%	73.20	362.93	51.97	2.13	7.16			-	134.47

Notes pertaining to tables C19 & C20:

Costs are expressed as real levelized \$/MWh costs in CY 2002 dollars

Environmental Adders: Levelized \$/Ton

SO_2:	\$294
NOx:	\$2,000
Hg:	\$100,000 \$/lb
CO_2:	\$7

Utilization Factors based on IRP Results (on average):

	Capacity Factor (%)
Coal	91.0%
CCCT - East	74.0%
CCCT - West	86.0%
Peakers - East	12.0%
Peakers - West	23.0%

Unless the combined forced and maintenance outage rates are less than above.

SYSTEM LOAD FORECAST

See Appendix K for more information on modeling of System Load Forecst.

The loads for east and west control areas under a median scenario are summarized in table C.21. The load forecast reflects loads growing at an average rate of 2.2% per year. The east system continues to grow faster than the west system, averaging annual growth rates of 2.2% and 2.0% respectively over the forecast horizon.

Table C.21 System Load Forecast for PacifiCorp Control Areas

Fiscal Year	East		West	
	Peak	Total GWH	Peak	Total GWH
2004	5,319	34,805	4,516	27,380
2005	5,417	35,536	4,556	27,560
2006	5,526	36,184	4,529	26,868
2007	5,685	37,002	4,596	27,311
2008	5,798	37,695	4,398	26,099
2009	5,877	38,447	3926*	23586*
2010	6,005	39,315	4,020	23,947
2011	6,112	40,183	4,111	24,339
2012	6,267	41,018	4,095	24,633
2013	6,386	42,038	4,299	25,250
2014	6,483	43,007	4,351	25,760
2015	6,676	43,931	4,448	26,358
2016	6,814	44,921	4,546	27,029
2017	6,979	45,992	4,774	27,665
2018	7,127	47,550	4,887	28,346
2019	7,309	48,886	4,956	29,021
2020	7,477	50,395	4,991	29,581
2021	7,722	51,671	5,160	30,170
2022	7,933	53,198	5,300	30,846
2023	8,160	54,552	5,399	31,364

West: Mid-Columbia and West Main
East: Wyoming, Goshen, Utah, and Idaho

* Load decrease is do to the experation of the Clark Co. PUD contract (see Purchases West, Table C.2)

System Losses
Transmission system losses are netted in the loads as stipulated in FERC form 714 (4.48% real loss rate, schedule 9).

THERMAL PLANT EMISSION RATES

Table C.22 Thermal Plant Emission Rates for PacifiCorp Generation Plants
(prior to emission control technology)

Emission Rates Prior to Control Technology for PacifiCorp Units lbs/MMBtu (except Hg – lbs/trillion Btu)					
Unit Name	**Unit No.**	**SO_2**	**NO_x**	**Hg**	**CO_2**
Blundell	1	-	-	-	-
Carbon	1	0.71	0.43	4.2	205
Carbon	2	0.73	0.43	4.2	205
Cholla	4	0.61	0.27	3.94	205
Colstrip	3	0.10	0.4	-	205
Colstrip	4	0.09	0.41	-	205
Craig	1	0.23	0.36	-	205
Craig	2	0.23	0.37	-	204
Dave Johnston	1	0.78	0.43	4.20	205
Dave Johnston	2	0.78	0.43	4.31	205
Dave Johnston	3	0.77	0.58	3.52	205
Dave Johnston	4	0.5	0.43	4.93	205
Gadsby	1	0.0006	0.11	-	119
Gadsby	2	0.0006	0.11	-	119
Gadsby	3	0.0006	0.08	-	119
Hayden	1	0.13	0.43	-	205
Hayden	2	0.13	0.36	-	205
Hermiston	1	-	0.01	-	119
Hermiston	2	-	0.01	-	119
Hunter	1	0.18	0.42	2.57	205
Hunter	2	0.18	0.42	2.79	205
Hunter	3	0.1	0.4	0.70	205
Huntington	1	0.21	0.42	2.71	205
Huntington	2	1.01	0.42	3.16	205
Jim Bridger	1	0.3	0.4	2.77	205
Jim Bridger	2	0.3	0.39	2.83	205
Jim Bridger	3	0.3	0.39	2.68	205
Jim Bridger	4	0.17	0.4	2.45	205
Little Mountain	1	-	0.4	-	119
Naughton	1	1.12	0.52	3.61	205
Naughton	2	1.12	0.49	1.73	204
Naughton	3	0.5	0.35	2.31	204
Wyodak	1	0.5	0.33	3.97	205

THERMAL PLANT FORCED OUTAGE RATES

Maintenance outage rates were based on average historical plant information developed by PacifiCorp. Historical outage rates were adjusted to account for operational items such as ramp rates, station service during maintenance outages, energy generated in deviation from reported capacity.

Table C.23 Forced Outage Rates

Forced Outage Rates - Unplanned and Maintenance Outages									Used in Multisym	
Unit ID	Base Generator Capability (Used in HR Curves)	Transmsn Outage as a Portion of other Outages	Forced Outage Hrs per 1,000 Sched. Hrs.	Maint. Outage Hrs per 1,000 Sched. Hrs.	Reserve Shutdown Hrs per 1,000 Period. Hrs.	Unplanned RateAvg 4yrs Avail	Unplanned Rate Less Trans Outages	Fiscal 2002 2003 Budget 2/19/2002 FOR 2002 3	Model FOR	Model MOR
Blundell	23.0		0.5%	0.55%	0.02%	15.96%	15.96%	0.40%	0.40%	0.55%
Carbon 1	70.0		3.5%	0.00%	0.09%	13.13%	13.13%	7.20%	7.20%	0.00%
Carbon 2	105.0		1.4%	0.98%	0.00%	10.70%	10.70%	2.20%	2.20%	0.98%
Cholla 4	380.0		7.4%	0.04%	0.00%	8.14%	8.14%	4.10%	4.10%	0.04%
Colstrip 3	72.0		9.9%	0.88%	0.00%	14.87%	14.87%	0.00%	9.92%	0.88%
Colstrip 4	72.0		9.1%	1.03%	0.00%	14.15%	14.15%	0.00%	9.09%	1.03%
Craig 1	82.5		1.3%	0.79%	0.00%	5.58%	5.58%	0.00%	1.27%	0.79%
Craig 2	82.5		3.0%			5.18%	5.18%	0.00%	2.98%	0.00%
Dave Johnston 1	106.0	0.03	2.1%	0.51%	0.00%	6.96%	6.75%	2.70%	2.62%	0.51%
Dave Johnston 2	106.0	0.03	1.4%	0.71%	0.00%	7.90%	7.67%	3.30%	3.20%	0.71%
Dave Johnston 3	220.0	0.03	6.9%	2.51%	0.00%	11.75%	11.40%	7.50%	7.28%	1.65%
Dave Johnston 4	330.0	0.03	7.6%	2.35%	0.00%	13.57%	13.16%	5.00%	4.85%	2.35%
Gadsby 1	60.0		0.1%	0.00%	52.76%	4.04%	4.04%	0.70%	0.70%	0.00%
Gadsby 2	75.0		4.7%	1.50%	23.87%	5.49%	5.49%	4.20%	4.20%	1.10%
Gadsby 3	100.0		2.8%	0.86%	12.46%	7.44%	7.44%	4.60%	4.60%	0.86%
Gadsby pk1	42.0					5.00%	5.00%	0.80%	0.80%	0.00%
Gadsby pk2	42.0					5.00%	5.00%	0.80%	0.80%	0.00%
Gadsby pk3	42.0					5.00%	5.00%	0.80%	0.80%	0.00%
Hayden 1	45.0		8.3%	0.90%	0.00%	12.42%	12.42%	0.00%	8.30%	0.90%
Hayden 2	33.0		1.2%	0.00%	0.00%	6.95%	6.95%	0.00%	1.22%	0.00%
Hermiston 1	125.0					4.52%	4.52%	0.00%	0.00%	0.00%
Hermiston 2	125.0					4.59%	4.59%	0.00%	0.00%	0.00%

Table C.23 Forced Outage Rates (Continued)

Forced Outage Rates - Unplanned and Maintenance Outages										
				Used in Multisym			Used in Multisym			
Unit ID	Unpl-for-mor	% time Remaining (1-for-mor)	Equiv Production Rate	T1 - 2/3 of total time	T2 - Remaining Time (1-2/3-for-mor)	Offset (Guess)	P1 - Production Level 2/3	P1 MW	P2 - Production Level 1/3 rest of time	P2 MW
Blundell	15.0%	99.0%	84.8%	0.660	33.0%	5.0%	89.8%	20.7	74.8%	17.2
Carbon 1	5.9%	92.8%	93.6%	0.619	30.9%	5.0%	98.6%	69.0	83.6%	58.5
Carbon 2	7.5%	96.8%	92.2%	0.645	32.3%	5.0%	97.2%	102.1	82.2%	86.3
Cholla 4	4.0%	95.9%	95.8%	0.639	32.0%	4.2%	100.0%	380.0	87.5%	332.5
Colstrip 3	4.1%	89.2%	95.4%	0.595	29.7%	4.6%	100.0%	72.0	86.3%	62.2
Colstrip 4	4.0%	89.9%	95.5%	0.599	30.0%	4.5%	100.0%	72.0	86.5%	62.3
Craig 1	3.5%	97.9%	96.4%	0.653	32.6%	3.6%	100.0%	82.5	89.2%	73.6
Craig 2	2.2%	97.0%	97.7%	0.647	32.3%	2.3%	100.0%	82.5	93.2%	76.9
Dave Johnston 1	3.6%	96.9%	96.3%	0.646	32.3%	3.7%	100.0%	106.0	88.8%	94.1
Dave Johnston 2	3.8%	96.1%	96.1%	0.641	32.0%	3.9%	100.0%	106.0	88.3%	93.6
Dave Johnston 3	2.5%	91.1%	97.3%	0.607	30.4%	2.7%	100.0%	220.0	91.9%	202.1
Dave Johnston 4	6.0%	92.8%	93.6%	0.619	30.9%	5.0%	98.6%	325.3	83.6%	275.8
Gadsby 1	3.3%	99.3%	96.6%	0.662	33.1%	3.4%	100.0%	60.0	89.9%	53.9
Gadsby 2	0.2%	94.7%	99.8%	0.631	31.6%	0.2%	100.0%	75.0	99.4%	74.5
Gadsby 3	2.0%	94.5%	97.9%	0.630	31.5%	2.1%	100.0%	100.0	93.7%	93.7
Gadsby pk1	4.2%	99.2%	95.8%	0.661	33.1%	4.2%	100.0%	42.0	87.3%	36.7
Gadsby pk2	4.2%	99.2%	95.8%	0.661	33.1%	4.2%	100.0%	42.0	87.3%	36.7
Gadsby pk3	4.2%	99.2%	95.8%	0.661	33.1%	4.2%	100.0%	42.0	87.3%	36.7
Hayden 1	3.2%	90.8%	96.4%	0.605	30.3%	3.6%	100.0%	45.0	89.3%	40.2
Hayden 2	5.7%	98.8%	94.2%	0.659	32.9%	5.0%	99.2%	32.7	84.2%	27.8
Hermiston 1	4.5%	100.0%	95.5%	0.667	33.3%	4.5%	100.0%	125.0	86.5%	108.1
Hermiston 2	4.6%	100.0%	95.4%	0.667	33.3%	4.6%	100.0%	125.0	86.2%	107.8

Table C.23 Forced Outage Rates (Continued)

Forced Outage Rates - Unplanned and Maintenance Outages									Used in Multisym	
	Base Generator Capability (Used in HR Curves)	Transmsn Outage as a Portion of other Outages	Forced Outage Hrs per 1,000 Sched. Hrs.	Maint. Outage Hrs per 1,000 Sched. Hrs.	Reserve Shutdown Hrs per 1,000 Period. Hrs.	Unplanned RateAvg 4yrs Avail R.Eddy 5-6-02	Unplanned Rate Less Trans Outages	Fiscal 2002 2003 Budget 2/19/2002 FOR 2002-3	Model FOR	Model MOR
Hunter 1	403.1		7.72%	2.31%	0.00%	10.87%	10.87%	4.40%	4.40%	2.31%
Hunter 2	259.3		5.34%	1.82%	0.00%	11.73%	11.73%	4.60%	4.60%	1.82%
Hunter 3	460.0		3.66%	1.23%	0.00%	10.36%	10.36%	3.10%	3.10%	1.23%
Huntington 1	440.0		6.30%	0.33%	0.00%	9.48%	9.48%	5.60%	5.60%	0.33%
Huntington 2	455.0		6.51%	0.36%	0.00%	9.06%	9.06%	5.90%	5.90%	0.36%
James River						18.27%	18.27%	0.00%	0.00%	0.00%
Jim Bridger 1	353.0	0.18	4.04%	0.73%	0.09%	8.74%	7.16%	3.00%	2.46%	0.73%
Jim Bridger 2	353.0	0.18	4.44%	0.80%	0.44%	9.65%	7.92%	4.50%	3.69%	0.80%
Jim Bridger 3	353.0	0.18	2.00%	0.52%	0.00%	10.02%	8.22%	2.90%	2.38%	0.52%
Jim Bridger 4	353.0	0.18	5.57%	1.07%	0.28%	11.40%	9.35%	4.80%	3.94%	1.07%
Little Mountain	14.0					4.81%	4.81%	3.30%	3.30%	0.00%
Naughton 1	160.0		1.44%	1.04%	0.00%	7.08%	7.08%	1.00%	1.00%	1.04%
Naughton 2	210.0		2.69%	3.10%	0.00%	9.51%	9.51%	2.00%	2.00%	3.10%
Naughton 3	330.0		2.71%	3.56%	0.00%	9.99%	9.99%	4.00%	4.00%	3.56%
Wyodak	268.0		0.69%	2.37%	0.00%	7.69%	7.69%	0.60%	0.60%	2.37%
West Valley 1	42.0					5.00%	5.00%	0.80%	0.80%	0.00%
West Valley 2	42.0					5.00%	5.00%	0.80%	0.80%	0.00%
West Valley 3	42.0					5.00%	5.00%	0.80%	0.80%	0.00%
West Valley 4	42.0					5.00%	5.00%	0.80%	0.80%	0.00%
West Valley 5	42.0					5.00%	5.00%	0.80%	0.80%	0.00%
Average			**4.14%**	**1.13%**	**3.10%**	**8.62%**	**8.62%**	**2.33%**	**2.33%**	**0.75%**
FOR/MOR Avg				3.66						

Table C.23 Forced Outage Rates (Continued)

Forced Outage Rates - Unplanned and Maintenance Outages				Used in Multisym			Used in Multisym			
	Unpl-for-mor	% time Remaining (1-for-mor)	Equiv Production Rate	T1 - 2/3 of total time	T2 - Remaining Time (1-2/3-for-mor)	Offset (Guess)	P1 - Production Level 2/3	P1 MW	P2 - Production Level 1/3 rest of time	P2 MW
Hunter 1	4.2%	93.3%	95.5%	0.622	31.1%	4.5%	100.0%	403.10	86.6%	349.13
Hunter 2	5.3%	93.6%	94.3%	0.624	31.2%	5.0%	99.3%	257.55	84.3%	218.65
Hunter 3	6.0%	95.7%	93.7%	0.638	31.9%	5.0%	98.7%	454.01	83.7%	385.01
Huntington 1	3.5%	94.1%	96.2%	0.627	31.4%	3.8%	100.0%	440.00	88.7%	390.25
Huntington 2	2.8%	93.7%	97.0%	0.625	31.2%	3.0%	100.0%	455.00	91.0%	414.25
James River	18.3%	100.0%	81.7%	0.667	33.3%	5.0%	86.7%	-	71.7%	0.00
Jim Bridger 1	4.0%	96.8%	95.9%	0.645	32.3%	4.1%	100.0%	353.00	87.7%	309.54
Jim Bridger 2	3.4%	95.5%	96.4%	0.637	31.8%	3.6%	100.0%	353.00	89.2%	314.96
Jim Bridger 3	5.3%	97.1%	94.5%	0.647	32.4%	5.0%	99.5%	351.30	84.5%	298.35
Jim Bridger 4	4.3%	95.0%	95.4%	0.633	31.7%	4.6%	100.0%	353.00	86.3%	304.62
Little Mountain	1.5%	96.7%	98.4%	0.645	32.2%	1.6%	100.0%	14.00	95.3%	13.35
Naughton 1	5.0%	98.0%	94.9%	0.653	32.7%	5.0%	99.9%	159.76	84.9%	135.76
Naughton 2	4.4%	94.9%	95.4%	0.633	31.6%	4.6%	100.0%	210.00	86.1%	180.73
Naughton 3	2.4%	92.4%	97.4%	0.616	30.8%	2.6%	100.0%	330.00	92.1%	303.99
Wyodak	4.7%	97.0%	95.1%	0.647	32.3%	4.9%	100.0%	268.00	85.4%	228.82
West Valley1	4.2%	99.2%	95.8%	0.661	33.1%	4.2%	100.0%	42.00	87.3%	36.67
West Valley 2	4.2%	99.2%	95.8%	0.661	33.1%	4.2%	100.0%	42.00	87.3%	36.67
West Valley 3	4.2%	99.2%	95.8%	0.661	33.1%	4.2%	100.0%	42.00	87.3%	36.67
West Valley 4	4.2%	99.2%	95.8%	0.661	33.1%	4.2%	100.0%	42.00	87.3%	36.67
West Valley 5	4.2%	99.2%	95.8%	0.661	33.1%	4.2%	100.0%	42.00	87.3%	36.67
Average	**5.5%**	**96.9%**	**94.3%**	**0.646**	**32.3%**	**5.0%**	**99.3%**	**-**	**84.3%**	**0.00**

THERMAL PLANT OPERATING LIFE

Table C.24 Thermal Plant Retirement Schedule

1.	Blundell	2021
2.	Carbon	2010
3.	Cholla	2025
4.	Colstrip	2029
5.	Craig	2024
6.	Gadsby	2007
7.	Gadsby Peakers	2027
8.	Hayden	2024
9.	Hermiston	2031
10.	Hunter	2025
11.	Huntington	2019
12.	J Bridger	2020
13.	James River	2016
14.	Johnston	2020
15.	Little Mountain	2006
16.	Naughton	2022
17.	Wyodak	2022

Electricity Supply Assumptions:

1. Plant design life is equal to 40 years
2. Recommended life is equal to the stipulated dates in the year 2000 depreciation study except for Naughton.
3. Naughton's recommended life has been extended to 54 years.
4. Blundell life assumed to be equal to the steam purchase contract period of 30 year (from 1991).
5. Gadsby 4, 5, & 6 lives assumed to be equal to 25 years (simple cycle gas turbines).
6. The 2007 date for the Gadsby retirement is the stipulated depreciation date and reflects a weighted average age of these units at 54 years and is consistent with the longest life assumptions PacifiCorp are currently making for thermal assets.
7. Hermiston life assumed to be equal to the contract period of 35 years.
8. James River life assumed to be equal to the contract period of 20 years
9. Little Mountain was extended to 2006 to match its existing contract life.
10. Life estimates do not include the potential influence of emissions limitations. If there is a Carbon Tax or any other environmental constraint beyond what we think will come out of Clean Skies, even MACT, will cause some of the older plants to become uneconomical and shorten their depreciation lives.

THERMAL PLANT VARIABLE O&M COSTS

Variable O&M (VOM) costs for plants fully owned by PacifiCorp were calculated by escalating base 1995 variable O&M costs at 2.5%. The Table C.25 lists the 1995 VOM costs in $/MWh.

Table C.25 Thermal Plant Variable O&M Costs

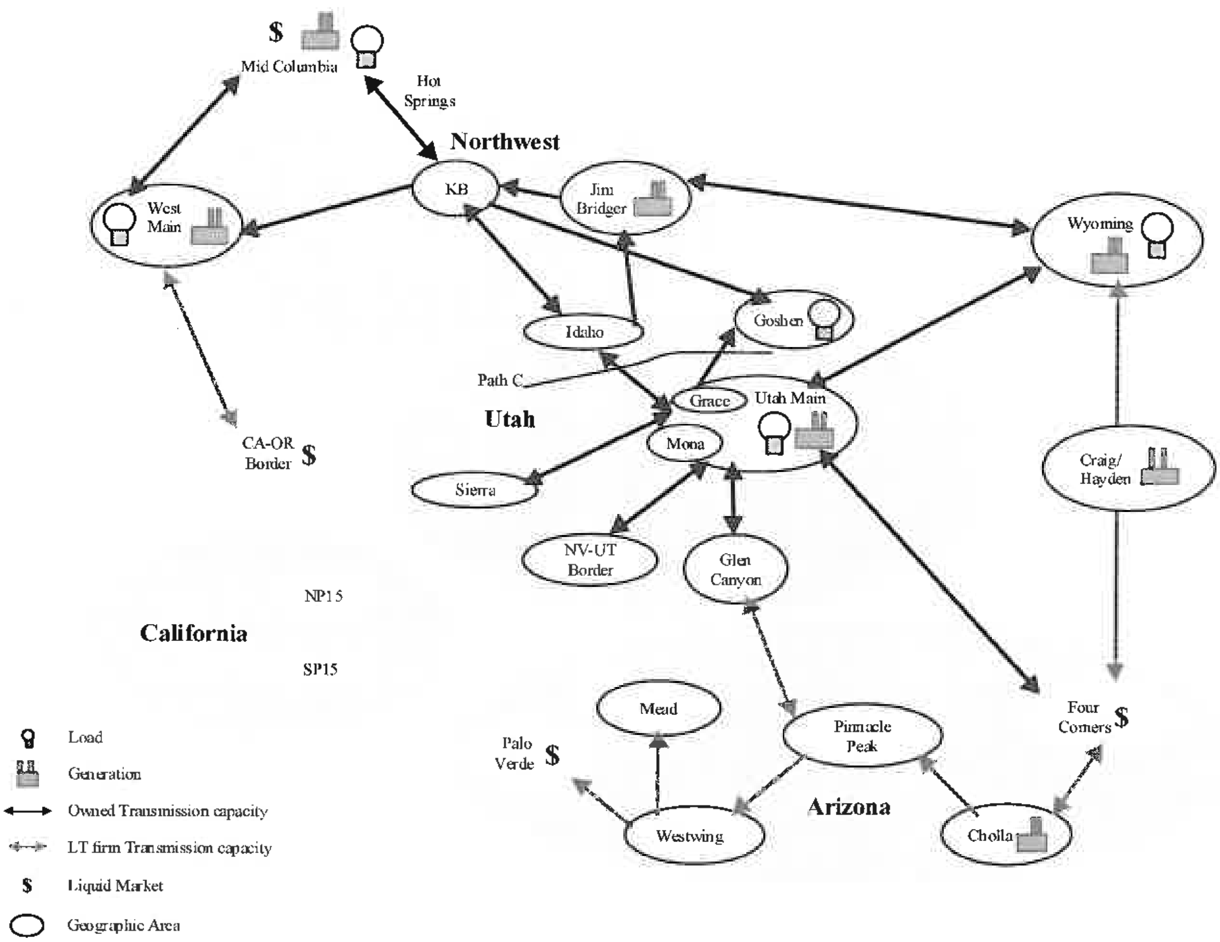
Variable O&M	PacifiCorp Plants, 1995, $/MWh
Hunter 1	0.40
Hunter 2	0.40
Hunter 3	0.40
Huntington 1	0.26
Huntington 2	0.26
Dave Johnston 1	0.19
Dave Johnston 2	0.19
Dave Johnston 3	0.19
Dave Johnston 4	0.19
Wyodak	0.67
Jim Bridger 1	0.46
Jim Bridger 2	0.46
Jim Bridger 3	0.46
Jim Bridger 4	0.46
Naughton 1	0.21
Naughton 2	0.21
Naughton 3	0.21
Carbon	0.23
Gadsby	0.30

TRANSMISSION

Transmission System

Capacity allocations for PacifiCorp's power supply and trading activities are based on long term firm OASIS reservations. The IRP topology includes 22 bubbles designed to capture transmission congestion and allow for capturing real values from the diversified markets. The transfer capabilities are PacifiCorp Merchant functions firm rights on the lines, and do not reflect the availability or physical capabilities of the lines. Loop flow impacts are considered. Figure C.2 illustrates the Transmission Topology modeled in this IRP.

Figure C.2 IRP Transmission Topology



RTO / Congestion Charges

These are not currently modeled. A detailed analysis of the impacts of the RTO and congestion needs to be undertaken in a future IRP when more detail of the impacts are known.

WHOLESALE ELECTRICITY MARKET PRICES FORECAST

Prices are modeled from 2002 through 2031 on a fiscal year basis for Mid Columbia, COB, and Palo Verde.

The curves is a blend derived from near-term forward prices from the market and long-term fundamental price scenarios simulated in the MIDAS model. Market prices as of August 01, 2002 were used for blending. The MIDAS cases were run on August 1, 2002.

- The deterministic analysis uses the medium – Cyclical Growth case, 08-01-02 market prices blended with the MIDAS Cyclical Growth (CG16).
- Similarly, the Natural Gas market prices used are for a medium case.

The blending of forward market prices and fundamental model prices uses the following methodology:

- Forward market prices are solely used through May 2005.
- June through November 2005 is weighted 75% forward market 25% MIDAS.
- December 2005 through May 2006 is a 50-50 weight between market and MIDAS.
- June through November 2006 is weighted 25% market 75% MIDAS.
- Beginning December 2006 only MIDAS results are used.

Table C.26 Wholesale Market Prices

Flat Prices (7X24) Fiscal Year Period		Medium Price Forecast COB	PV	MdC
Apr-03	Mar-04	$ 32.10	$ 30.84	$ 30.12
Apr-04	Mar-05	$ 32.91	$ 32.29	$ 31.03
Apr-05	Mar-06	$ 35.16	$ 32.68	$ 33.35
Apr-06	Mar-07	$ 39.34	$ 33.54	$ 38.94
Apr-07	Mar-08	$ 44.50	$ 37.34	$ 44.99
Apr-08	Mar-09	$ 49.50	$ 43.15	$ 49.88
Apr-09	Mar-10	$ 42.23	$ 38.66	$ 42.53
Apr-10	Mar-11	$ 44.92	$ 41.58	$ 44.90
Apr-11	Mar-12	$ 50.94	$ 47.69	$ 50.91
Apr-12	Mar-13	$ 54.12	$ 50.66	$ 53.42
Apr-13	Mar-14	$ 48.50	$ 46.54	$ 48.06
Apr-14	Mar-15	$ 53.57	$ 51.71	$ 53.12
Apr-15	Mar-16	$ 57.62	$ 55.22	$ 57.10
Apr-16	Mar-17	$ 58.26	$ 56.42	$ 57.89
Apr-17	Mar-18	$ 58.76	$ 58.39	$ 57.77
Apr-18	Mar-19	$ 60.42	$ 60.57	$ 59.74
Apr-19	Mar-20	$ 60.94	$ 61.48	$ 60.19
Apr-20	Mar-21	$ 60.82	$ 62.61	$ 60.25
Apr-21	Mar-22	$ 62.40	$ 63.19	$ 61.72
Apr-22	Mar-23	$ 63.96	$ 64.77	$ 63.26
Apr-23	Mar-24	$ 65.56	$ 66.39	$ 64.84
Apr-24	Mar-25	$ 67.20	$ 68.05	$ 66.46
Apr-25	Mar-26	$ 68.88	$ 69.75	$ 68.12
Apr-26	Mar-27	$ 70.60	$ 71.49	$ 69.83
Apr-27	Mar-28	$ 72.37	$ 73.28	$ 71.57
Apr-28	Mar-29	$ 74.18	$ 75.11	$ 73.36
Apr-29	Mar-30	$ 76.03	$ 76.99	$ 75.20
Apr-30	Mar-31	$ 77.93	$ 78.91	$ 77.08
Apr-31	Mar-32	$ 79.88	$ 80.88	$ 79.00

Table C.27 Spot Market Prices

	Medium Price Forecast			Medium Price Forecast		
	COB	PV	MdC	COB	PV	MdC
		HLH			LLH	
Jan-03	40.50	33.75	38.00	32.00	22.00	28.75
Feb-03	36.00	33.25	35.50	31.50	22.00	28.50
Mar-03	35.50	32.75	33.50	27.75	22.25	26.00
Apr-03	26.00	34.00	24.75	20.00	22.00	17.50
May-03	25.75	34.25	25.00	18.00	20.50	16.50
Jun-03	26.25	35.75	25.25	18.50	22.25	17.50
Jul-03	40.00	39.00	33.75	25.50	23.00	25.75
Aug-03	43.86	48.71	37.87	26.98	25.99	26.00
Sep-03	43.47	45.94	37.86	27.25	24.75	26.00
Oct-03	41.36	40.84	39.87	29.00	20.50	28.75
Nov-03	37.69	32.13	36.76	29.00	20.50	28.75
Dec-03	39.45	32.03	39.25	29.00	20.50	28.75
Jan-04	39.14	35.79	38.85	30.75	22.75	28.25
Feb-04	38.00	34.75	37.00	30.75	22.75	28.25
Mar-04	36.86	33.71	35.15	30.75	22.75	23.23
Apr-04	27.52	34.30	27.95	19.25	22.25	18.00
May-04	25.59	35.12	25.24	19.25	22.25	18.00
Jun-04	26.39	40.08	24.81	19.25	22.25	18.00
Jul-04	45.40	49.88	40.24	28.00	25.50	27.50
Aug-04	45.40	49.88	40.24	28.00	25.50	27.50
Sep-04	45.40	49.88	40.24	28.00	25.50	27.50
Oct-04	38.15	37.09	37.22	29.50	21.50	30.00
Nov-04	38.15	37.09	37.22	29.50	21.50	30.00
Dec-04	38.15	37.09	37.22	29.50	21.50	30.00
Jan-05	37.53	33.57	37.09	33.75	23.00	29.68
Feb-05	37.53	33.57	37.09	33.75	23.00	29.68
Mar-05	37.53	33.57	37.09	33.75	23.00	21.14
Apr-05	27.13	36.78	26.95	14.33	22.01	13.01
May-05	27.13	36.78	26.95	14.33	22.01	13.01
Jun-05	29.35	35.76	28.91	18.06	21.95	17.32
Jul-05	51.73	49.76	46.88	28.65	27.65	28.60
Aug-05	52.77	50.63	47.96	28.93	27.88	28.74
Sep-05	51.41	49.73	46.69	28.91	27.61	28.72
Oct-05	41.98	38.48	40.23	29.31	21.57	29.72
Nov-05	42.41	37.98	39.71	29.47	20.76	29.86
Dec-05	41.78	36.13	41.23	32.11	22.65	32.93

Wholesale Market Prices General Assumptions

All three trading hubs have the following **common** assumptions:

- Inflation: 2.5%
- Price Caps: After September 30, 2002, the price caps are set to $250 through 2020
- Reserve Margin: Reserve Margin was assumed to be 16% to account for forced outages and Operating Reserve requirements.
- Thermal
  - Forced outage rates for PacifiCorp's coal units (fiscal 2003) from the ten year plan were included, a 10% overall weighted average. Therefore, 10% forced outage rate was assumed for all other coal units in the WECC.
  - No coal plant retirements were included other than Carbon. There are 9,000 MW of new coal plants that are in the planning process, and we assumed that any coal plants that retire will be replaced by new ones over time. (Units that do retire: Gadsby units –

December 31, 2007, Carbon units – December 31, 2010, James River – December 31, 2016, Little Mountain – December 31, 2006).
   - Heat rates are Generation Engineering's latest.
   - New resource costs were adjusted to be compatible with the latest estimates from Generation Engineering and IRP.
- Environmental Costs: refer to emission costs section presented earlier in this appendix
- Emission Rates (see Table C.28)
   - PacifiCorp's units are represented with assumptions regarding an installation schedule for SO2 and NOx control equipment ranging from years 2005 to 2012, consistent with current PacifiCorp expectations for WRAP(Western Region Air Program). As this equipment is installed emission rates decrease. Individual installation dates and emission rate changes are included for Jim Bridger, Hunter, Huntington, Wyodak, Naughton and Cholla 4.
   - The emission rates for the balance of existing units in the WECC were decreased, similar to PacifiCorp's reductions, to comply with multi-pollutant legislation.

Table C.28 CG16 Emission Rates

	SO_2	NOx	Hg
Coal units	70%	30%	27%
Gas units	Very small	30%*	n/c
Oil units	n/c	n/c	n/c
* Units operating in SP15 are currently in the process of installing SCRs or other controls, so a 90% reduction in NOx was assumed.			

- RTO Assumptions: We assumed the WECC would be split into three RTOs - RTO West, CAISO and West Connect. An average wheeling rate of $2.20/hop was included to represent an average of the proposed RTO external interface access fees. We assumed $3.20 for the AC and DC Intertie to account for heavy RTO West exports to California. All off peak wheeling costs were set to half of the on peak wheeling charges.
- Hydrogeneration: Hydrogeneration assumptions were as follows:
   - 2002 - approximately 88% of a median Hydrogeneration condition
   - January through May, 2003 - 90% of a median Hydrogeneration condition
   - 2003 (balance) –2020 - median Hydrogeneration conditions were assumed

<u>Wholesale Market Prices Case-Specific Assumptions</u>

Medium Prices CG16 Cyclic Growth

The Cyclic Growth scenario depicts the gas and electric industries exhibiting cyclic supply additions that, on average, maintain balance with demand. Gas prices settle at approximately $3.50 by 2004. Increasing demand and production costs increase gas prices to the $4.70 range by 2015, then prices escalate 2.5% each year until 2020. Aggressive WECC generation additions during the 2001-03 time frame restore balance and adequate reserves to the electric markets, and then keep pace with modest demand growth, averaging just over 2% through 2020.

- Demand growth: 2.1 %/year
- New resource costs: escalating at 2.0 %/year
- Gas prices: PIRA base forecasts for both short and long term

Table C.29provides a summary of the MIDAS Price Model Assumptions for Official Curves August 6, 2002

Table C.29 MIDAS Price Model Assumptions

Key Assumptions in Forecasts	MEDIUM – CG16B BASE Blended with 08-01-02 Forward Market Prices
WECC Demand Growth For PacifiCorp loads in MIDAS, growth rates from IRP were included as shown in the table below. The growth rates shown in this table are exclusive of PacifiCorp's loads.	2003 to 2020: After 2002 there was a permanent 1% demand destruction (due to conservation efforts) applied to the base forecast. 2004-2010: 2.1 % Demand growth 2010-2020: 2.0% Demand growth
Gas Prices	PIRA forecasts for both short and long term
New Resource Costs: – Capital costs, VOM, FOM (See chart below)	Capital Costs 5% decrease from current costs in 2004 Escalating at 2.0% nominal/year
Annual Build Limits for new generation picked by the model	Hardwired New Units 2000 to 2004: 32,395 MW Added by Model 2005 to 2020: 41,010 MW

Table C.30 New Resource Option Assumptions for CG16 Base Case

New Resource Option Assumptions for CG16B Base Case*	**SCCT 1** LM6000	**SCCT 2 7EA Peaker**	**CCT 1 7FA 1x1 CCCT**	**CCT 2 7FA 2x1 CCCT**	**Utah Coal**
Size	90 MW	115 MW	235 MW	490 MW	575 MW
Capital Costs $/kW	717	458	786	600	1,389
Fixed O & M $/kW per year	9.73	9.55	11.29	6.65	27.39
Variable O & M $/MWH	3.37	2.72	1.67	1.53	0.73
Heat Rate Btu/kWh	10,223	12,176	7,235	7,074	9,483
*2002 Dollars at ISO conditions, includes AFUDC	*Capital costs and fixed O&M were adjusted for elevation in each load center	*Capital carrying charge 15%			

Table C.31 Nominal Capital Escalation

Nominal Capital Escalation	Medium Growth CG16 Base
2001	0%
2002	0%
2003	0%
2004	-5%
2005	2%
2006	2%
2007	2%
2008	2%
2009	2%
2010	2%
2011	2%
2012	2%
2013	2%
2014	2%
2015	2%
2016	2%
2017	2%
2018	2%
2019	2%
2020	2%

Table C.32 Demand Growth Assumptions

Demand Growth Assumptions	**PacifiCorp COB**	**PacifiCorp West**	**Utah**	**PacifiCorp Idaho**	**Wyoming**
CG16B Base	2.12%	2.12%	3.09%	1.81%	1.50%

APPENDIX D – PORTFOLIO SUMMARY TABLES

Portfolio	Portfolio Capacity Table D.1	Portfolio Capital Cost Table D.2
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Alternative Technology II	238	264
Coal/Gas III	239	265
PacifiCorp Build - I	240	265
Gas/Coal I	241	266
Gas/Coal II	242	266
Gas/Coal III	243	267
PacifiCorp Build II	244	267
Peakers	245	268
Renewable	246	269
Alternative Technology I	247	270
All Gas II	248	271
Wyoming Coal	249	271
All Gas I	250	272
Coal/Gas II	251	272
Coal/Gas I	252	273
Transmission - 1000MW DC	253	273
Transmission - 2000MW DC	254	274
Transmission - Asset Build Market	255	274
Coal/Gas III - 10%	256	275
Gas/Coal I - 10%	257	275
PacifiCorp Build II - 10%	258	276
All Gas II - 10%	259	276

Note: DSM programs have no capital costs, hence were omitted from Table D-2. See Tables in Appendix E for DSM Real Levelized costs.

Table D.1 Portfolio Capacity
This table itemizes incremental resources added by year for both East and West, for each of the portfolios.

	Summer CY / FY	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	
	Portfolio Summary (MW)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**Total MW's**
	Diversified Portfolio I											
East STF/IF	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
DSM	Class 1 DSM (load control - peak MW capability)	30	30	31								91
DSM	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (East - installed capacity in MW)				200		200		200		120	720
IF	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 (East)			200							300	500
STF	East Market (Short Term)	500										500
West STF/IF	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
DSM	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Wind (West - installed capacity in MW)			100		200		200		200		700
IF	Flat Contract (7X24)								200			200
IF	3-Year Flat Off-Peak	500			-500							0
	CCCT (Albany)				570							570
	Reserve Peakers (West)			230						230		460
STF	West Market (Short Term)	500										500
IF	Peaking Contract									100		100
		1790	834	1458	1792	2406	3130	3394	3858	4932	5602	

Total = 7,336

Plant Invest and LT = 4715

Purchases = 2375

STF Total 500 500 1000

STF/IF Total 175 175 350

IF Total 225 200 500 100 1,025

WIND 700 720 1420

Peaker Plant 200 500 460 1160

Base load 575 480 510 570 2,135

DSM 123 91 22 236

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006 2005	2007 2006	2008 2007	2009	2010	2011	2012	2013	Total MW's
	Diversified Portfolio II											
East	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (East - installed capacity in MW)				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
	Peakers (Mona)										200	200
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200						300		500
West	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Wind (West - installed capacity in MW)			100		200		200		200		700
	CCCT (K. Falls)								255			255
	3-Year Flat Off-Peak	500			-500							0
	CCCT (Albany)				570							570
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230							230	460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Diversified Portfolio III											
East	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (East - installed capacity in MW)				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
	Peakers (Mona)										200	200
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
West	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Wind (West - installed capacity in MW)			100		200		200		200		700
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2003 2004	2004 2005	2005 2006	2006 2007	2008	2009	2010	2011	2012	2013	Total MW's
	Diversified Portfolio IV											
East	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (aMW added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (East - installed capacity in MW)				200		200		200		120	720
	Super Peak Contract	225				-225						0
	CCCT (Mona)						480			480		960
	CCCT (Gadsby Repower)					510						510
	Peaker East (Mona)										200	200
	Reserve Peakers (East)			200							300	500
	East Market (Short Term)	500										500
West	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 1 DSM (load control - peak MW capability)	0	0	0	0	0	0	0	0	0	0	0
	Class 2 DSM (aMW added each year)	5	2	2	2	2	2	2	2	2	0	22
	Wind (West - installed capacity in MW)			100		200		200		200		700
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	CCCT (Albany)				570							570
	Reserve Peakers (West) (K. Falls)			230						230		460
	West Market (Short Term)	500										500
	Flat Contract Mid C									100		100

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Alternative Technology II											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (East - installed capacity in MW)				200		200		200		120	720
	Class 1 DSM (Load control - peak MW capability - UTM)					30						30
	Class 2 DSM (MWa added each year)			8	15	15	15	15	15	15	15	113
	Geothermal (East)				50							50
	Fuel Cells	2	8	10	10	20	20	20	20	20	20	150
	CHP					25		25		25		75
	Super Peak Contract	225			-225							0
	CCCT (Gadsby Repower)				510							510
	Reserve Peakers (East)			200						100	200	500
	East Market (Short Term)	500										500
	CCCT (Mona)									480		480
	Mona Peakers									100		100
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Geothermal (West)				50							50
	Wind (West - installed capacity in MW)			100		200		200		200		700
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Reserve Peakers (West)			230			115			115		460
	Peaking Contract								100			100
	West Market (Short Term)	500										500
	CCCT (K. Falls)				510							510

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Coal/Gas III											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	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 (East)			200							300	500
	East Market (Short Term)	500										500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	CCCT (Albany)				570							570
	Reserve Peakers (West)			230						230		460
	West Market (Short Term)	500										500
	Peaking Contract									100		100

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	PacifiCorp Build - I											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)									575		575
	CCCT (Mona)				480							480
	CCCT (Gadsby Repower)						510					510
	Peakers (Mona)										200	200
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200						300		500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	CCCT (K. Falls)								255			255
	3-Year Flat Off-Peak	500			-500							0
	CCCT (Albany)				570							570
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230							230	460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Gas/Coal I											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)									575		575
	CCCT (Mona)						480					480
	CCCT (Gadsby Repower)				510							510
	Peakers (Mona)										200	200
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Gas/Coal II											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	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
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200						300		500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230							230	460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Gas/Coal III											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)									575		575
	CCCT (Mona)				480							480
	CCCT (Gadsby Repower)					510						510
	Peakers (Mona)										200	200
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200						300		500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	PacifiCorp Build II											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)									575		575
	CCCT (Mona)						480					480
	CCCT (Gadsby Repower)				510							510
	Peakers (Mona)										200	200
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	CCCT (K. Falls)								255			255
	3-Year Flat Off-Peak	500			-500							0
	CCCT (Albany)				570							570
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230							230	460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Peakers											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)									575		575
	CCCT (Mona)				240							240
	CCCT (Gadsby Repower)						510					510
	Peakers (Mona)				200						300	500
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200						300		500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230							230	460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Renewable											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (aMW added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (East - installed capacity in MW)				200		200		200		120	720
	Geothermal (East)				50							50
	Mona CCCT (2x1)						480					480
	Super Peak Contract	225			-225							0
	CCCT (Gadsby Repower)				510							510
	Reserve Peakers (East)			200						100	200	500
	East Market (Short Term)	500										500
	CCCT (Mona)									480		480
	Mona Peakers									100		100
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	0	0	0	0	0	0	0	0	0	0	0
	Class 2 DSM (aMW added each year)	5	2	2	2	2	2	2	2	2	0	22
	Wind (West - installed capacity in MW)									200		200
	Geothermal (West)				50							50
	Wind (West - installed capacity in MW)			100		200		200				500
	Class 1 DSM (lc peak MW capability - UTM)											0
	Class 2 DSM (aMW added each year)											0
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Reserve Peakers (West) (K. Falls)			230			115			115		460
	Peaking Contract								100			100
	West Market (Short Term)	500										500
	CCCT (K. Falls)				510							510

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Alternative Technology I											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (East - installed capacity in MW)			600					120			720
	Class 1 DSM (lc peak MW capability - UTM)					30						30
	Class 2 DSM (MWa added each year)			8	15	15	15	15	15	15	15	113
	Geothermal (East)				50							50
	Fuel Cells	2	8	10	10	20	20	20	20	20	20	150
	CHP					25		25		25		75
	Super Peak Contract	225			-225							0
	CCCT (Gadsby Repower)				510							510
	Reserve Peakers (East)			400					100			500
	East Market (Short Term)	500										500
	CCCT (Mona)									480		480
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Geothermal (West)				50							50
	Wind (West - installed capacity in MW)			500					200			700
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Reserve Peakers (West)			460		230			115			805
	Peaking Contract								100			100
	West Market (Short Term)	500										500
	CCCT (K. Falls)									285		285

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	All Gas II											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	CCCT (Mona)						480			480		960
	CCCT (Gadsby Repower)				510							510
	Peakers (Mona)									100	200	300
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Wyoming Coal											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Bridger 5)									530		530
	CCCT (Mona)				480							480
	CCCT (Gadsby Repower)						510					510
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200						300		500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230							230	460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	All Gas I											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	CCCT (Gadsby Repower)				510							510
	CCCT (Mona)					480				480		960
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
	Peakers (Mona)									100	200	300
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Coal/Gas II											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Peakers (Mona, LM6000)			280								280
	Coal Base Load (Hunter 4)					575						575
	CCCT (Gadsby Repower)									510		510
	Super Peak Contract (mona)	225				-225						0
	Peakers (Mona)									200	200	400
	Extend Gadsby					235				-235		0
	East Market (Short Term)	500										500
	Reserve Peakers (East)			100						400		500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)				230						230	460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Coal/Gas I											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Peakers (Mona, LM6000)			280								280
	Coal Base Load (Hunter 4)					575						575
	CCCT (Gadsby Repower)									510		510
	Super Peak Contract	225			-225							0
	Peakers (Mona)				200						200	400
	East Market (Short Term)	500										500
	Reserve Peakers (East)			100						400		500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)				230						230	460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Transmission - 1000MW DC											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)						575					575
	Coal Base Load (Bridger 5)									530		530
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (Albany)				570							570
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Transmission - 2000MW DC											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)						575					575
	Coal Base Load (Bridger 5)									530		530
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (Albany)				570							570
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Transmission - Asset Build Market											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Peaker East (Harry Allen)			200							500	700
	CCCT (Mona)				480		480					960
	CCCT (Harry Allen)									510		510
	East Market (Short Term)	500										500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Coal/Gas III - 10%											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	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 (East)										200	200
	East Market (Short Term)	500										500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	CCCT (Albany)				570							570
	Reserve Peakers (West)									230		230
	West Market (Short Term)	500										500
	Peaking Contract									100		100

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	Gas/Coal I - 10%											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)									575		575
	CCCT (Mona)										480	480
	CCCT (Gadsby Repower)					510						510
	Peakers (Mona)				200		200			200		600
	East Market (Short Term)	500										500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (Albany)				570							570
	West Market (Short Term)	500										500

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MW's
	PacifiCorp Build II - 10%											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)									575		575
	CCCT (Mona)										480	480
	CCCT (Gadsby Repower)					510						510
	Peakers (Mona)				200		200			200		600
	East Market (Short Term)	500										500
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	CCCT (K. Falls)								255			255
	3-Year Flat Off-Peak	500			-500							0
	CCCT (Albany)				570							570
	West Market (Short Term)	500										500
	Reserve Peakers (West)										230	230

Table D.1 Portfolio Capacity (Continued)

	Portfolio Summary (MW)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**Total MW's**
	All Gas II - 10%											
East	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 1 DSM (load control - peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Super Peak Contract	225			-225							0
	CCCT (Mona)						480			480		960
	CCCT (Gadsby Repower)				510							510
	Peakers (Mona)									100	200	300
	East Market (Short Term)	500										500
	Reserve Peakers (East)										200	200
West	Wind (installed capacity in MW)	0	0	93	66	48	66	71	74	74	83	573
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (K. Falls)				510							510
	West Market (Short Term)	500										500
	Reserve Peakers (West)									230		230

Table D.2 Portfolio Capital Cost

This table is the incremental capital cost by year for each of the portfolios. The capital costs are itemized by addition, for both resources and associated transmission; the total line accounts for the combined capital costs.

	Portfolio Capital Costs (MM $2002)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	Diversified Portfolio I										
	Wind – Wyoming				200		200		200		
	Wind - Utah										120
	Wind (West)			100		200		200		200	
	Coal Base Load (Hunter 4)					799					
	CCCT 2 - (Mona)										
	CCCT 2 - Duct Firing (Mona)									15	
	CCCT (Gadsby Repower)						295				
	CCCT - Duct Firing (Gadsby Repower)						14				
	Peakers (Mona)										92
	Peakers (East)			108							162
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)			111						111	
	Transmission	46		22	41	118	63	4	12	23	56
Total	**4,159**	**46**		**341**	**565**	**1,117**	**572**	**204**	**212**	**673**	**430**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Diversified Portfolio II										
	Wind – Wyoming				200		200		200		
	Wind – Utah										120
	Wind (West)			100		200		200		200	
	Coal Base Load (Hunter 4)									799	
	CCCT 2 - (Mona)				323						
	CCCT 2 - Duct Firing (Mona)				15						
	CCCT (Gadsby Repower)						295				
	CCCT - Duct Firing (Gadsby Repower)						14				
	Peakers (East)			108						162	
	Peakers (Mona)										92
	CCCT (K. Falls)								155		
	CCCT Duct Firing (K. Falls)								7		
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)			111							111
	Transmission	46		22	49	4	63	4	37	125	60
Total	**4,346**	**46**		**341**	**911**	**204**	**572**	**204**	**399**	**1,286**	**382**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Diversified Portfolio III											
	Wind - Wyoming					200		200		200		
	Wind - Utah											120
	Wind (West)				100		200		200		200	
	Coal Base Load (Hunter 4)										799	
	CCCT 2 - (Mona)							323				
	CCCT 2 - Duct Firing (Mona)							15				
	CCCT (Gadsby Repower)					295						
	CCCT - Duct Firing (Gadsby Repower)					14						
	Peakers (Mona)											92
	Peakers (East)				108							162
	CCCT (K. Falls)											
	CCCT Duct Firing (K. Falls)					14						
	Reserve Peakers (West)				111						111	
	Transmission		46		22	65	4	47	4	20	121	56
Total		**4,160**	**46**		**341**	**899**	**204**	**586**	**204**	**220**	**1,231**	**430**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	Diversified Portfolio IV										
	Wind - Wyoming				200		200		200		
	Wind - Utah										120
	Wind (West)			100		200		200		200	
	CCCT 2 - (1x1) (Mona)						323				
	CCCT 2 - Duct Firing (1x1) (Mona)						15				
	CCCT 2 - (1x1) (Mona)									323	
	CCCT 2 - Duct Firing (1x1) (Mona)									15	
	CCCT (Gadsby Repower)					295					
	CCCT - Duct Firing (Gadsby Repower)					14					
	Peakers (Mona, SCCT Frame)										92
	Peakers (East, SCCT Frame)			108							
	Peakers (East, SCCT Frame)										162
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)			111						111	
	Transmission	46		22	41	28	47	4	12	70	9
Total	**3,592**	**46**		**341**	**565**	**537**	**586**	**204**	**212**	**719**	**382**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Alternative Technology II										
	Wind - Wyoming				200		200		200		
	Wind - Utah										120
	Blundell Upgrade				94						
	CHP (Non CT)					16		16		16	
	CCCT (Gadsby Repower)				295						
	CCCT - Duct Firing (Gadsby Repower)				14						
	Peakers (East)			108						54	108
	Peakers (Mona)									46	
	CCCT 2 - (Mona)									323	
	CCCT 2 - Duct Firing (Mona)									15	
	Fuel Cells		12	15	15	30	30	30	30	30	30
	Geothermal (West)				94						
	Wind (West)			100		200		200		200	
	Reserve Peakers (West)			111			55			55	
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Transmission	46		28	75	4	45	4	14	96	1
Total	**3,704**	**49**	**12**	**362**	**1,112**	**250**	**330**	**250**	**244**	**835**	**259**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Coal/Gas III										
	Coal Base Load (Hunter 4)					799					
	CCCT 2 - (Mona)									323	
	CCCT 2 - Duct Firing (Mona)									15	
	CCCT (Gadsby Repower)						295				
	CCCT - Duct Firing (Gadsby Repower)						14				
	Peakers (Mona)										92
	Peakers (East)			108							162
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)			111						111	
	Transmission	46		10	25	114	24			16	55
Total	**2,644**	**46**		**229**	**349**	**913**	**333**			**466**	**309**

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	PacifiCorp Build - I										
	Coal Base Load (Hunter 4)									799	
	CCCT 2 - (Mona)				323						
	CCCT 2 - Duct Firing (Mona)				15						
	CCCT (Gadsby Repower)						295				
	CCCT - Duct Firing (Gadsby Repower)						14				
	Peakers (East)			108						162	
	Peakers (Mona)										92
	CCCT (K. Falls)								155		
	CCCT Duct Firing (K. Falls)								7		
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)			111							111
	Transmission	46		10	33		24		25	118	59
Total	**2,831**	**46**		**229**	**695**		**333**		**187**	**1,079**	**262**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)		**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	Gas/Coal I											
	Coal Base Load (Hunter 4)										799	
	CCCT 2 - (Mona)							323				
	CCCT 2 - Duct Firing (Mona)							15				
	CCCT (Gadsby Repower)					295						
	CCCT - Duct Firing (Gadsby Repower)					14						
	Peakers (Mona)											92
	Peakers (East)				108							162
	CCCT (K. Falls)					311						
	CCCT Duct Firing (K. Falls)					14						
	Reserve Peakers (West)				111						111	
	Transmission		46		10	49		8		8	114	55
Total		**2,645**	**46**		**229**	**683**		**347**		**8**	**1,024**	**309**

	Portfolio Capital Costs (MM $2002)		**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	Gas/Coal II											
	Coal Base Load (Hunter 4)										799	
	CCCT 2 - (Mona)					323						
	CCCT 2 - Duct Firing (Mona)					15						
	CCCT (Gadsby Repower)							295				
	CCCT - Duct Firing (Gadsby Repower)							14				
	Peakers (Mona)											92
	Peakers (East)				108						162	
	CCCT (K. Falls)					311						
	CCCT Duct Firing (K. Falls)					14						
	Reserve Peakers (West)				111							111
	Transmission		46		10	33		24			118	59
Total		**2,645**	**46**		**229**	**697**		**333**			**1,079**	262

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Gas/Coal III										
	Coal Base Load (Hunter 4)									799	
	CCCT 2 - (Mona)				323						
	CCCT 2 - Duct Firing (Mona)				15						
	CCCT (Gadsby Repower)					295					
	CCCT - Duct Firing (Gadsby Repower)					14					
	Peakers (East)			108						162	
	Peakers (Mona)										92
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Reserve Peakers (West)			111						111	
	Transmission	46		10	33	24				126	51
Total	2,645	**46**		**229**	**697**	**333**				**1,198**	**143**

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	PacifiCorp Build II										
	Coal Base Load (Hunter 4)									799	
	CCCT 2 - (Mona)						323				
	CCCT 2 - Duct Firing (Mona)						15				
	CCCT (Gadsby Repower)				295						
	CCCT - Duct Firing (Gadsby Repower)				14						
	Peakers (Mona)										92
	Peakers (East)			108							162
	CCCT (K. Falls)								155		
	CCCT Duct Firing (K. Falls)								7		
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)			111							111
	Transmission	52		29	24		8	25		122	55
Total	2,831	**52**		**248**	**657**		**347**	**25**	**162**	**921**	**420**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Peakers										
	Coal Base Load (Hunter 4)									799	
	CCCT 1 - (Mona)				162						
	CCCT 1 - Duct Firing (Mona)				8						
	CCCT (Gadsby Repower)						295				
	CCCT - Duct Firing (Gadsby Repower)						14				
	Peakers (Mona)				92						137
	Peakers (East)			108						162	
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Reserve Peakers (West)			111							111
	Transmission	46		10	33		24			126	51
Total	**2,612**	**46**		**229**	**619**		**333**			**1,086**	**299**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Renewable										
	Wind - Wyoming				200		200		200		
	Wind - Utah										120
	Blundell Upgrade				94						
	Peakers (Mona, SCCT Frame)									46	
	CCCT (Gadsby Repower)				295						
	CCCT - Duct Firing (Gadsby Repower)				14						
	Peakers (East, SCCT Frame)			108						54	108
	CCCT 2 - (1x1) (Mona)						323			323	
	CCCT 2 - Duct Firing (1x1) (Mona)						15			15	
	Geothermal (West)				94						
	Wind (West)			100		200		200		200	
	Reserve Peakers (West)			111			55			55	
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Transmission	46		28	75	4	53	4	14	96	1
Total	**3,777**	**46**		**347**	**1,097**	**204**	**647**	**204**	**214**	**790**	**229**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	Alternative Technology I										
	Wind - Wyoming			600							
	Wind - Utah								120		
	Blundell Upgrade				94						
	CHP (Non CT)					16		16		16	
	CCCT (Gadsby Repower)				295						
	CCCT - Duct Firing (Gadsby Repower)				14						
	Peakers (East)			216					54		
	CCCT 2 - (Mona)									323	
	CCCT 2 - Duct Firing (Mona)									15	
	Fuel Cells	3	12	15	15	30	30	30	30	30	30
	Geothermal (West)				94						
	Wind (West)			500					200		
	Reserve Peakers (West)			222		111			55		
	CCCT (Albany)									155	
	CCCT - Duct Firing (Albany)									7	
	Transmission	46		78	52	8			9	33	
Total	**3,574**	**49**	**12**	**1,630**	**564**	**165**	**30**	**46**	**468**	**580**	**30**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	All Gas II										
	CCCT 2 - (Mona)						323			323	
	CCCT 2 - Duct Firing (Mona)						15			15	
	CCCT (Gadsby Repower)				295						
	CCCT - Duct Firing (Gadsby Repower)				14						
	Peakers (Mona)									46	92
	Peakers (East)			108							162
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Reserve Peakers (West)			111						111	
	Transmission	46		10	49		8			68	55
Total	2,177	**46**		**229**	**683**		**347**			**563**	**309**

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Wyoming Coal										
	Coal Base Load (Bridger 5)									796	
	CCCT 2 - (Mona)				323						
	CCCT 2 - Duct Firing (Mona)				15						
	CCCT (Gadsby Repower)						295				
	CCCT - Duct Firing (Gadsby Repower)						14				
	Peakers (East)			108						162	
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Reserve Peakers (West)			111							111
	Transmission	46		10	33		24			323	8
Total	2,704	**46**		**229**	**697**		**333**			**1,281**	**119**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	All Gas I										
	CCCT (Gadsby Repower)				295						
	CCCT - Duct Firing (Gadsby Repower)				14						
	CCCT 2 - (Mona)					323				323	
	CCCT 2 - Duct Firing (Mona)					15				15	
	Peakers (Mona)									46	92
	Peakers (East)			108							162
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Reserve Peakers (West)			111						111	
	Transmission	46		10	49	8				68	8
Total	2,129	**46**		**229**	**683**	**347**				**564**	**261**

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Coal/Gas II										
	Coal Base Load (Hunter 4)					799					
	East Greenfield SCCT Aero			236							
	CCCT (Gadsby Repower)									295	
	CCCT - Duct Firing (Gadsby Repower)									14	
	Peakers (East)			54						216	
	Peakers (Mona)									92	92
	Gadsby Extension 4 years					0	1	0	1		
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Reserve Peakers (West)				111						111
	Transmission	46		6	31	114				36	12
Total	2,592	**46**		**296**	**467**	**913**	**1**	**0**	**1**	**653**	**215**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Coal/Gas I										
	Coal Base Load (Hunter 4)					799					
	East Greenfield SCCT Aero			236							
	CCCT (Gadsby Repower)									295	
	CCCT - Duct Firing (Gadsby Repower)									14	
	Peakers (East)			54						216	
	Peakers (Mona)				92						92
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Reserve Peakers (West)				111						111
	Transmission	46		14	29	114				32	57
Total	**2,636**	**46**		**304**	**556**	**913**				**557**	**260**

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Transmission - 1000MW DC										
	Coal Base Load (Hunter 4)						799				
	Coal Base Load (Bridger 5)									796	
	Peakers (East)			108							162
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)			111						111	
	Transmission	46		10	25	715	114			327	4
Total	**3,651**	**46**		**229**	**349**	**715**	**913**			**1,234**	**166**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Transmission - 2000MW DC										
	Coal Base Load (Hunter 4)						799				
	Coal Base Load (Bridger 5)									796	
	Peakers (East)			108							162
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)			111						111	
	Transmission	46		10	25		1,204			327	4
Total	**4,026**	**46**		**229**	**349**		**2,003**			**1,234**	**166**

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Transmission - Asset Build Market										
	Peakers (Mona)			92							229
	CCCT 2 - (Mona)				323		323				
	CCCT 2 - Duct Firing (Mona)				15		15				
	CCCT (H. Allen)									311	
	CCCT Duct Firing (H. Allen)									14	
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Reserve Peakers (West)			111						111	
	Transmission	46		29	33		8			328	95
Total	**2,409**	**46**		**231**	**697**		**347**			**764**	**324**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Coal/Gas III - 10%										
	Coal Base Load (Hunter 4)					799					
	CCCT 2 - (Mona)									323	
	CCCT 2 - Duct Firing (Mona)									15	
	CCCT (Gadsby Repower)						295				
	CCCT - Duct Firing (Gadsby Repower)						14				
	Peakers (Mona)										92
	Peakers (East)										108
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)									111	
	Transmission	46			25	114	24			16	55
Total	**2,361**	**46**			**349**	**913**	**333**			**465**	**254**

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Gas/Coal I - 10%										
	Coal Base Load (Hunter 4)									799	
	CCCT 2 - (Mona)										323
	CCCT 2 - Duct Firing (Mona)										15
	CCCT (Gadsby Repower)					295					
	CCCT - Duct Firing (Gadsby Repower)					14					
	Peakers (Mona)				92		92			92	
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Transmission	46		25	4	24	4			165	24
Total	**2,338**	**46**		**25**	**420**	**333**	**96**			**1,056**	**363**

Table D.2 Portfolio Capital Cost (Continued)

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	PacifiCorp Build II - 10%										
	Coal Base Load (Hunter 4)									799	
	CCCT 2 - (Mona)										323
	CCCT 2 - Duct Firing (Mona)										15
	CCCT (Gadsby Repower)					295					
	CCCT - Duct Firing (Gadsby Repower)					14					
	Peakers (Mona)				92		92			92	
	CCCT (K. Falls)								155		
	CCCT Duct Firing (K. Falls)								7		
	CCCT (Albany)				309						
	CCCT - Duct Firing (Albany)				15						
	Reserve Peakers (West)										111
	Transmission	46			29	24	4		25	165	38
Total	**2,650**	**46**			**445**	**333**	**96**		**187**	**1,056**	**487**

	Portfolio Capital Costs (MM $2002)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	All Gas II - 10%										
	CCCT 2 - (Mona)						323			323	
	CCCT 2 - Duct Firing (Mona)						15			15	
	CCCT (Gadsby Repower)				295						
	CCCT - Duct Firing (Gadsby Repower)				14						
	Peakers (Mona)									46	92
	Peakers (East)										162
	CCCT (K. Falls)				311						
	CCCT Duct Firing (K. Falls)				14						
	Reserve Peakers (West)									111	
	Transmission	46		6	49		8			68	55
Total	**1,954**	**46**		**6**	**683**		**347**			**563**	**309**

APPENDIX E – ANALYSIS RESULTS

INDEX - SCORECARDS

Table E.1 Scorecard Results

VALUE MEASURE	**Diversified I**	**Diversified II**	**Diversified III**	**Diversified IV**	**Alternative Technology II**	**Coal/Gas III**
Comparative PVRR Ranking	*1*	*2*	*3*	*4*	*5*	*6*
Present Value Rev. Req't (20 Year $000)	**12,313,159**	**12,337,893**	**12,360,185**	**12,395,185**	**12,558,743**	**12,650,880**
Percent Greater Than Lowest PVRR	0.000%	0.201%	0.382%	0.666%	1.994%	2.370%
Incremental Net Variable Power Cost	9,779,027	9,841,314	9,992,809	10,456,417	10,300,434	10,116,734
Incremental Real Levelized Fixed Cost	2,343,907	2,306,354	2,177,151	1,748,542	2,012,751	2,343,921
DSM Real Levelized	190,225	190,225	190,225	190,225	245,558	190,225
Capital Cost (2002$-millions)	2,643	2,831	2,644	2,077	2,190	2,643
Emissions (2004-2023 PVRR $000)	21,750	32,826	(7,237)	(122,127)	(180,773)	112,087
CO2 (thousand tons 2009-2023)	847,919	851,850	841,248	811,477	798,101	866,376
CO2 (% of cap)	105%	105%	104%	100%	99%	107%
SO2 (thousand tons 2009-2023)	652	655	654	645	639	661
SO2 (% of cap)	63%	63%	63%	62%	62%	64%
NOx (thousand tons 2009-2023)	1,046	1,049	1,047	1,036	1,031	1,058
NOx (% of cap)	102%	102%	102%	101%	100%	103%
Hg (thousand tons 2009-2023)	0.0038	0.0036	0.0036	0.0024	0.0024	0.0039
Hg (% of cap)	69%	66%	66%	44%	44%	71%
Market Purchases (10 Year)						
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%
PAC East Average MW	10	9	9	11	8	12
PAC West (% of load)	1.1%	1.1%	1.1%	1.1%	1.1%	1.3%
PAC West Average MW	80	80	83	80	81	95
Market Sales						
PAC East (% of owned Generation)	7.1%	6.9%	7.0%	6.7%	6.9%	6.8%
PAC East Average MW	323	313	316	300	308	305
PAC West (% of owned Generation)	11.0%	10.7%	10.7%	10.8%	10.8%	10.0%
PAC West Average MW	304	304	296	304	303	275
Unit Capacity Factors (2014)						
Existing Coal East	84.3%	84.6%	84.2%	86.2%	85.0%	86.4%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.3%	3.0%	3.5%	4.2%	3.7%	4.3%
IRP CCCT East	47.8%	47.0%	47.5%	63.3%	53.1%	62.3%
IRP Coal East	91.0%	91.0%	91.0%			91.0%
IRP Peaker East	4.6%	4.5%	5.0%	5.5%	6.4%	6.4%
Existing CCCT West	34.2%	31.5%	35.2%	37.8%	36.8%	51.5%
Existing Coal West	86.0%	86.2%	86.1%	86.9%	86.3%	87.1%
Existing Other West	90.9%	90.9%	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	77.4%	77.2%	78.5%	81.8%	80.1%	84.9%
IRP Peaker West	9.0%	11.9%	10.1%	10.1%	9.8%	12.1%
East West Transfers (MWHs)						
2004 East-West Transfer	799,978	801,435	799,978	801,435	798,733	799,978
2014 East-West Transfer	1,077,393	1,124,739	1,083,438	766,831	897,874	995,183
Percent Increase/Decrease over 2004	135%	140%	135%	96%	112%	124%
2004 West-East Transfer	1,901,936	1,899,981	1,901,936	1,899,981	1,915,797	1,901,937
2014 West-East Transfer	1,303,125	1,332,926	1,293,016	1,588,166	1,437,129	1,386,160
Percent Increase/Decrease over 2004	69%	70%	68%	84%	75%	73%

Table E.1 Scorecard Results (continued)

VALUE MEASURE	PacifiCorp Build I	Gas/Coal I	Gas/Coal II	Gas/Coal III	PacifiCorp Build II	Peakers
Comparative PVRR Ranking	*7*	*8*	*9*	*10*	*11*	*12*
Present Value Rev. Req't (20 Year $000)	**12,678,966**	**12,706,361**	**12,714,668**	**12,742,655**	**12,747,670**	**12,759,278**
Percent Greater Than Lowest PVRR	2.597%	2.819%	2.886%	3.112%	3.153%	3.247%
Incremental Net Variable Power Cost	10,182,373	10,338,971	10,342,096	10,334,365	10,261,794	10,410,451
Incremental Real Levelized Fixed Cost	2,306,368	2,177,165	2,182,347	2,218,065	2,295,651	2,158,602
DSM Real Levelized	190,225	190,225	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,831	2,644	2,644	2,644	2,831	2,612
Emissions (2004-2023 PVRR $000)	**116,512**	**75,362**	**75,804**	**75,508**	**118,056**	**69,740**
CO2 (thousand tons 2009-2023)	869,627	858,529	858,563	858,564	870,006	855,803
CO2 (% of cap)	108%	106%	106%	106%	108%	106%
SO2 (thousand tons 2009-2023)	662	662	662	662	663	664
SO2 (% of cap)	64%	64%	64%	64%	64%	64%
NOx (thousand tons 2009-2023)	1,059	1,058	1,058	1,058	1,059	1,060
NOx (% of cap)	103%	103%	103%	103%	103%	103%
Hg (thousand tons 2009-2023)	0.0036	0.0036	0.0036	0.0036	0.0036	0.0036
Hg (% of cap)	66%	66%	66%	66%	66%	66%
Market Purchases (10 Year)						
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%
PAC East Average MW	10	10	10	9	10	13
PAC West (% of load)	1.3%	1.3%	1.3%	1.3%	1.3%	1.4%
PAC West Average MW	95	100	100	100	96	101
Market Sales						
PAC East (% of owned Generation)	6.6%	6.6%	6.6%	6.6%	6.6%	6.2%
PAC East Average MW	295	296	294	299	298	275
PAC West (% of owned Generation)	9.8%	9.7%	9.7%	9.7%	9.7%	9.5%
PAC West Average MW	276	266	267	266	273	264
Unit Capacity Factors (2014)						
Existing Coal East	86.5%	86.5%	86.5%	86.5%	86.5%	86.9%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	4.0%	4.4%	4.5%	4.4%	4.2%	5.7%
IRP CCCT East	61.2%	62.8%	60.8%	62.8%	62.0%	65.1%
IRP Coal East	91.0%	91.0%	91.0%	91.0%	91.0%	91.0%
IRP Peaker East	6.4%	6.5%	6.7%	6.5%	6.7%	8.1%
Existing CCCT West	50.6%	52.5%	52.8%	52.5%	52.4%	58.2%
Existing Coal West	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%
Existing Other West	90.9%	90.9%	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	85.8%	85.1%	86.5%	85.1%	85.4%	86.1%
IRP Peaker West	15.0%	12.1%	12.5%	12.1%	15.8%	12.9%
East West Transfers (MWHs)						
2004 East-West Transfer	801,435	799,978	799,978	799,978	801,435	799,978
2014 East-West Transfer	997,995	1,070,178	1,025,049	1,070,178	1,037,075	912,676
Percent Increase/Decrease over 2004	125%	134%	128%	134%	129%	114%
2004 West-East Transfer	1,899,981	1,901,937	1,901,937	1,901,937	1,899,981	1,901,937
2014 West-East Transfer	1,424,921	1,328,237	1,379,916	1,328,237	1,370,958	1,566,113
Percent Increase/Decrease over 2004	75%	70%	73%	70%	72%	82%

Table E.1 Scorecard Results (continued)

VALUE MEASURE	Renewable	Alternative Technology I	All Gas II	Wyoming Coal	All Gas I	Coal/Gas II
Comparative PVRR Ranking	*13*	*14*	*15*	*16*	*17*	*18*
Present Value Rev. Req't (20 Year $000)	**12,767,268**	**12,770,441**	**12,865,485**	**12,868,170**	**12,889,074**	**12,908,186**
Percent Greater Than Lowest PVRR	3.688%	0.945%	4.106%	4.128%	4.297%	4.452%
Incremental Net Variable Power Cost	10,576,052	8,758,428	10,824,942	10,484,941	10,841,858	10,289,150
Incremental Real Levelized Fixed Cost	2,000,991	3,766,455	1,850,318	2,193,003	1,856,991	2,428,811
DSM Real Levelized	190,225	245,558	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,237	3,590	2,176	2,703	2,129	2,591
Emissions (2004-2023 PVRR $000)	**(138,826)**	**(215,927)**	**(51,246)**	**69,622**	**(53,274)**	**96,219**
CO2 (thousand tons 2009-2023)	807,598	790,291	826,857	856,839	826,251	859,189
CO2 (% of cap)	100%	98%	102%	106%	102%	106%
SO2 (thousand tons 2009-2023)	644	639	650	662	650	666
SO2 (% of cap)	62%	61%	63%	64%	63%	64%
NOx (thousand tons 2009-2023)	1,035	1,029	1,043	1,059	1,043	1,063
NOx (% of cap)	101%	100%	101%	103%	101%	103%
Hg (thousand tons 2009-2023)	0.0024	0.0024	0.0030	0.0024	0.0030	0.0039
Hg (% of cap)	44%	44%	55%	44%	55%	71%
Market Purchases (10 Year)						
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%
PAC East Average MW	9	7	10	10	10	13
PAC West (% of load)	1.1%	1.5%	1.3%	1.4%	1.3%	1.4%
PAC West Average MW	82	109	100	101	100	103
Market Sales						
PAC East (% of owned Generation)	6.9%	6.9%	6.5%	6.5%	6.6%	6.2%
PAC East Average MW	310	309	289	291	294	274
PAC West (% of owned Generation)	10.7%	9.6%	9.7%	9.7%	9.7%	9.5%
PAC West Average MW	300	258	268	266	267	264
Unit Capacity Factors (2014)						
Existing Coal East	86.5%	85.3%	87.6%	86.9%	87.6%	87.0%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.6%	3.8%	5.3%	4.6%	5.2%	6.5%
IRP CCCT East	62.7%	55.1%	74.3%	66.0%	74.0%	74.7%
IRP Coal East				91.1%		91.0%
IRP Peaker East	5.2%	6.8%	7.4%	8.7%	9.7%	9.4%
Existing CCCT West	36.9%	43.4%	56.9%	53.9%	57.9%	64.4%
Existing Coal West	87.0%	86.5%	87.6%	87.0%	87.5%	87.2%
Existing Other West	90.9%	90.9%	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	82.2%	81.6%	86.7%	84.4%	86.3%	86.7%
IRP Peaker West	9.6%	11.3%	12.7%	12.7%	12.4%	13.6%
East West Transfers (MWHs)						
2004 East-West Transfer	799,126	798,733	801,634	801,634	800,207	801,634
2014 East-West Transfer	790,797	1,053,040	856,645	1,180,117	857,967	767,745
Percent Increase/Decrease over 2004	99%	132%	107%	147%	107%	96%
2004 West-East Transfer	1,902,380	1,915,797	1,901,727	1,901,727	1,904,207	1,901,727
2014 West-East Transfer	1,554,709	1,275,536	1,482,094	1,430,452	1,490,065	1,843,918
Percent Increase/Decrease over 2004	82%	67%	78%	75%	78%	97%

Table E.1 Scorecard Results (continued)

VALUE MEASURE	Coal/Gas I	Transmission 1000MW DC	Transmission 2000MW DC	Transmission Asset Build Market
Comparative PVRR Ranking	*19*	*20*	*21*	*22*
Present Value Rev. Req't (20 Year $000)	**12,909,633**	**13,017,821**	**13,217,807**	**13,221,223**
Percent Greater Than Lowest PVRR	4.464%	5.339%	6.957%	6.985%
Incremental Net Variable Power Cost	10,288,519	9,932,178	9,931,997	11,083,835
Incremental Real Levelized Fixed Cost	2,430,889	2,895,418	3,095,585	1,947,163
DSM Real Levelized	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,636	3,650	4,025	2,408
Emissions (2004-2023 PVRR $000)	**95,488**	**261,848**	**261,923**	**(82,685)**
CO2 (thousand tons 2009-2023)	859,091	897,011	897,019	816,619
CO2 (% of cap)	106%	111%	111%	101%
SO2 (thousand tons 2009-2023)	666	685	685	652
SO2 (% of cap)	64%	66%	66%	63%
NOx (thousand tons 2009-2023)	1,063	1,086	1,086	1,044
NOx (% of cap)	103%	106%	106%	101%
Hg (thousand tons 2009-2023)	0.0039	0.0039	0.0039	0.0034
Hg (% of cap)	71%	71%	71%	62%
Market Purchases (10 Year)				
PAC East (% of load)	0.2%	0.2%	0.2%	0.2%
PAC East Average MW	13	11	11	13
PAC West (% of load)	1.4%	1.3%	1.3%	1.4%
PAC West Average MW	103	93	93	104
Market Sales				
PAC East (% of owned Generation)	6.2%	6.2%	6.2%	6.2%
PAC East Average MW	273	275	275	273
PAC West (% of owned Generation)	9.6%	10.8%	10.8%	9.4%
PAC West Average MW	265	299	299	259
Unit Capacity Factors (2014)				
Existing Coal East	87.0%	86.9%	86.9%	88.0%
Existing Other East	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	6.5%	7.7%	7.7%	6.6%
IRP CCCT East	74.7%			47.1%
IRP Coal East	91.0%	91.0%	91.0%	
IRP Peaker East	9.4%	4.4%	4.4%	5.0%
Existing CCCT West	64.4%	57.5%	57.5%	58.1%
Existing Coal West	87.2%	86.3%	86.3%	87.6%
Existing Other West	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	86.7%	77.4%	77.4%	86.2%
IRP Peaker West	13.6%	13.1%	13.1%	14.2%
East West Transfers (MWHs)				
2004 East-West Transfer	801,634	801,026	801,026	800,207
2014 East-West Transfer	767,745	2,143,509	2,143,602	617,681
Percent Increase/Decrease over 2004	96%	268%	268%	77%
2004 West-East Transfer	1,901,727	1,905,609	1,905,609	1,904,207
2014 West-East Transfer	1,843,918	2,084,234	2,083,827	2,064,786
Percent Increase/Decrease over 2004	97%	109%	109%	108%

Table E.2 Top Four

VALUE MEASURE	Diversified I	Diversified II	Diversified III	Diversified IV
Comparative PVRR Ranking	*1*	*2*	*3*	*4*
Present Value Rev. Req't (20 Year $000)	**12,313,159**	**12,337,893**	**12,360,185**	**12,395,185**
Percent Greater Than Lowest PVRR	0.000%	0.201%	0.382%	0.666%
Incremental Net Variable Power Cost	9,779,027	9,841,314	9,992,809	10,456,417
Incremental Real Levelized Fixed Cost	2,343,907	2,306,354	2,177,151	1,748,542
DSM Real Levelized	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,643	2,831	2,644	2,077
Emissions (2004-2023 PVRR $000)	**21,750**	**32,826**	**(7,237)**	**(122,127)**
CO2 (thousand tons 2009-2023)	847,919	851,850	841,248	811,477
CO2 (% of cap)	105%	105%	104%	100%
SO2 (thousand tons 2009-2023)	652	655	654	645
SO2 (% of cap)	63%	63%	63%	62%
NOx (thousand tons 2009-2023)	1,046	1,049	1,047	1,036
NOx (% of cap)	102%	102%	102%	101%
Hg (thousand tons 2009-2023)	0.0038	0.0036	0.0036	0.0024
Hg (% of cap)	69%	66%	66%	44%
Market Purchases (10 Year)				
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%
PAC East Average MW	10	9	9	11
PAC West (% of load)	1.1%	1.1%	1.1%	1.1%
PAC West Average MW	80	80	83	80
Market Sales				
PAC East (% of owned Generation)	7.1%	6.9%	7.0%	6.7%
PAC East Average MW	323	313	316	300
PAC West (% of owned Generation)	11.0%	10.7%	10.7%	10.8%
PAC West Average MW	304	304	296	304
Unit Capacity Factors (2014)				
Existing Coal East	84.3%	84.6%	84.2%	86.2%
Existing Other East	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.3%	3.0%	3.5%	4.2%
IRP CCCT East	47.8%	47.0%	47.5%	63.3%
IRP Coal East	91.0%	91.0%	91.0%	
IRP Peaker East	4.6%	4.5%	5.0%	5.5%
Existing CCCT West	34.2%	31.5%	35.2%	37.8%
Existing Coal West	86.0%	86.2%	86.1%	86.9%
Existing Other West	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	77.4%	77.2%	78.5%	81.8%
IRP Peaker West	9.0%	11.9%	10.1%	10.1%
East West Transfers (MWHs)				
2004 East-West Transfer	799,978	801,435	799,978	801,435
2014 East-West Transfer	1,077,393	1,124,739	1,083,438	766,831
Percent Increase/Decrease over 2004	135%	140%	135%	96%
2004 West-East Transfer	1,901,936	1,899,981	1,901,936	1,899,981
2014 West-East Transfer	1,303,125	1,332,926	1,293,016	1,588,166
Percent Increase/Decrease over 2004	69%	70%	68%	84%

Table E.3 10% Planning Margin Results

VALUE MEASURE	Coal/Gas III - 10%	Gas/Coal I - 10%	PacifiCorp Build II - 10%	All Gas II - 10%
Comparative PVRR Ranking	*1*	*2*	*3*	*4*
Present Value Rev. Req't (20 Year $000)	**12,358,015**	**12,375,514**	**12,531,227**	**12,575,957**
Percent Greater Than Lowest PVRR	0.000%	0.142%	1.402%	1.764%
Incremental Net Variable Power Cost	10,152,586	10,390,255	10,343,447	10,859,037
Incremental Real Levelized Fixed Cost	2,015,203	1,795,034	1,997,554	1,526,695
DSM Real Levelized	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,361	2,337	2,649	1,953
Emissions (2004-2023 PVRR $000)	**107,467**	**76,542**	**113,300**	**(55,625)**
CO_2 (thousand tons 2009-2023)	865,034	858,103	867,972	825,534
CO_2 (% of cap)	107%	106%	107%	102%
SO_2 (thousand tons 2009-2023)	662	664	664	651
SO_2 (% of cap)	64%	64%	64%	63%
NO_x (thousand tons 2009-2023)	1,058	1,060	1,061	1,043
NO_x (% of cap)	103%	103%	103%	101%
Hg (thousand tons 2009-2023)	0.0039	0.0036	0.0036	0.0030
Hg (% of cap)	71%	66%	66%	55%
Market Purchases (10 Year)				
PAC East (% of load)	0.2%	0.2%	0.2%	0.2%
PAC East Average MW	13	16	16	11
PAC West (% of load)	1.3%	1.3%	1.3%	1.4%
PAC West Average MW	96	99	99	101
Market Sales				
PAC East (% of owned Generation)	6.7%	6.0%	6.0%	6.4%
PAC East Average MW	303	265	265	288
PAC West (% of owned Generation)	9.9%	9.7%	9.5%	9.6%
PAC West Average MW	273	270	270	265
Unit Capacity Factors (2014)				
Existing Coal East	86.5%	86.5%	86.6%	87.6%
Existing Other East	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	4.5%	4.1%	4.6%	5.3%
IRP CCCT East	62.3%	62.1%	62.4%	74.1%
IRP Coal East	91.0%	91.0%	91.0%	
IRP Peaker East	6.7%	8.1%	8.2%	7.6%
Existing CCCT West	50.9%	51.2%	52.3%	57.3%
Existing Coal West	87.1%	87.1%	87.2%	87.5%
Existing Other West	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	85.6%	85.8%	85.4%	87.1%
IRP Peaker West	11.9%	22.3%	22.3%	12.6%
East West Transfers (MWHs)				
2004 East-West Transfer	799,978	800,207	801,634	801,634
2014 East-West Transfer	1,028,459	1,022,495	1,041,889	859,466
Percent Increase/Decrease over 2004	129%	128%	130%	107%
2004 West-East Transfer	1,901,937	1,904,207	1,901,727	1,901,727
2014 West-East Transfer	1,382,455	1,385,407	1,330,305	1,511,294
Percent Increase/Decrease over 2004	73%	73%	70%	79%

Table E.4 CO2 $0/Ton: Allowance Used Is CY 2000 Actual Beginning In FY 2013

VALUE MEASURE	**Diversified I**	**Diversified II**	**Diversified III**	**Diversified IV**	**Renewable**
Comparative PVRR Ranking	*1*	*2*	*3*	*4*	*5*
Present Value Rev. Req't (20 Year $000)	**12,081,433**	**12,109,080**	**12,170,316**	**12,301,723**	**12,687,035**
Percent **Greater** Than Lowest NPV	0.000%	0.229%	0.736%	1.823%	5.013%
Incremental Net Variable Power Cost	9,547,301	9,612,501	9,802,940	10,362,955	10,495,818
Incremental Real Levelized Fixed Cost	2,343,907	2,306,354	2,177,151	1,748,542	2,000,991
DSM Real Levelized	190,225	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,643	2,831	2,644	2,077	2,237
Emissions (2004-2023 PVRR $000)	**(98,206)**	**(95,424)**	**(97,478)**	**(110,259)**	**(111,239)**
CO2 (thousand tons 2009-2023)	858,494	862,370	851,290	822,166	818,522
CO2 (% of cap)	106%	107%	105%	102%	101%
SO2 (thousand tons 2009-2023)	661	663	662	653	652
SO2 (% of cap)	64%	64%	64%	63%	63%
NOx (thousand tons 2009-2023)	1,057	1,059	1,057	1,045	1,044
NOx (% of cap)	103%	103%	103%	102%	101%
Hg (thousand tons 2009-2023)	0.0039	0.0036	0.0036	0.0024	0.0024
Hg (% of cap)	71%	66%	66%	44%	44%
Market Purchases (10 Year)					
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%	0.1%
PAC East Average MW	10	8	9	10	8
PAC West (% of load)	1.0%	0.9%	1.0%	0.9%	1.0%
PAC West Average MW	71	70	74	70	72
Market Sales					
PAC East (% of owned Generation)	8.0%	7.6%	7.7%	7.4%	7.6%
PAC East Average MW	366	346	349	336	346
PAC West (% of owned Generation)	11.6%	11.4%	11.4%	11.5%	11.4%
PAC West Average MW	325	327	319	327	323
Unit Capacity Factors (2014)					
Existing Coal East	86.5%	86.6%	86.4%	88.2%	88.3%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	4.7%	4.4%	4.8%	5.7%	5.1%
IRP CCCT East	48.6%	48.9%	49.1%	63.5%	63.6%
IRP Coal East	91.0%	91.0%	91.0%		
IRP Peaker East	6.1%	6.1%	6.3%	7.2%	6.9%
Existing CCCT West	37.7%	35.2%	39.1%	41.7%	41.5%
Existing Coal West	86.6%	86.8%	86.6%	87.3%	87.3%
Existing Other West	90.9%	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	76.5%	77.5%	77.2%	80.8%	80.9%
IRP Peaker West	13.9%	18.0%	15.1%	15.0%	14.4%
East West Transfers (MWHs)					
2004 East-West Transfer	801,406	803,845	801,406	803,845	800,549
2014 East-West Transfer	66,610	81,482	91,715	653,388	653,388
Percent Increase/Decrease over 2004	8%	10%	11%	81%	82%
2004 West-East Transfer	1,904,206	1,900,881	1,904,206	1,900,881	1,905,072
2014 West-East Transfer	3,688,834	3,658,366	3,587,543	1,838,300	1,786,538
Percent Increase/Decrease over 2004	194%	192%	188%	97%	94%

Table E.5 CO2 $2/Ton: Allowance Used Is CY 2000 Actual Beginning In FY 2013

VALUE MEASURE	Diversified I	Diversified II	Diversified III	Diversified IV	Renewable
Comparative PVRR Ranking	*1*	*2*	*3*	*4*	*5*
Present Value Rev. Req't (20 Year $000)	**12,123,125**	**12,159,816**	**12,213,900**	**12,326,941**	**12,709,547**
Percent Greater Than Lowest NPV	0.000%	0.303%	0.749%	1.681%	4.837%
Incremental Net Variable Power Cost	9,588,993	9,663,237	9,846,524	10,388,174	10,518,331
Incremental Real Levelized Fixed Cost	2,343,907	2,306,354	2,177,151	1,748,542	2,000,991
DSM Real Levelized	190,225	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,643	2,831	2,644	2,077	2,237
Emissions (2004-2023 PVRR $000)	**(71,318)**	**(62,214)**	**(71,495)**	**(105,291)**	**(108,343)**
CO2 (thousand tons 2009-2023)	856,752	860,430	849,418	820,036	816,412
CO2 (% of cap)	106%	106%	105%	101%	101%
SO2 (thousand tons 2009-2023)	660	662	661	652	652
SO2 (% of cap)	64%	64%	64%	63%	63%
NOx (thousand tons 2009-2023)	1,056	1,058	1,056	1,044	1,043
NOx (% of cap)	103%	103%	103%	101%	101%
Hg (thousand tons 2009-2023)	0.0039	0.0036	0.0036	0.0024	0.0024
Hg (% of cap)	71%	66%	66%	44%	44%
Market Purchases (10 Year)					
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%	0.1%
PAC East Average MW	10	9	9	10	8
PAC West (% of load)	1.0%	1.0%	1.0%	1.0%	1.0%
PAC West Average MW	73	72	76	73	74
Market Sales					
PAC East (% of owned Generation)	7.9%	7.4%	7.5%	7.2%	7.4%
PAC East Average MW	360	337	339	325	336
PAC West (% of owned Generation)	11.4%	11.2%	11.2%	11.3%	11.2%
PAC West Average MW	319	320	312	320	317
Unit Capacity Factors (2014)					
Existing Coal East	86.5%	86.9%	86.4%	88.2%	88.3%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	4.4%	3.9%	4.4%	5.3%	4.6%
IRP CCCT East	47.9%	47.5%	48.1%	62.8%	62.7%
IRP Coal East	91.0%	91.0%	91.0%		
IRP Peaker East	5.6%	5.6%	5.9%	6.6%	6.4%
Existing CCCT West	36.8%	34.3%	38.0%	40.4%	59.7%
Existing Coal West	86.6%	86.8%	86.6%	87.3%	40.2%
Existing Other West	90.9%	90.9%	90.9%	90.9%	87.3%
IRP CCCT West	76.2%	77.4%	75.9%	80.3%	90.9%
IRP Peaker West	12.4%	16.2%	13.6%	13.6%	94.0%
East West Transfers (MWHs)					
2004 East-West Transfer	801,406	803,845	801,406	803,845	800,549
2014 East-West Transfer	66,610	81,482	91,715	612,659	653,388
Percent Increase/Decrease over 2004	8%	10%	11%	76%	82%
2004 West-East Transfer	1,904,206	1,900,881	1,904,206	1,900,881	1,905,072
2014 West-East Transfer	3,688,834	3,658,366	3,587,543	1,838,300	1,786,538
Percent Increase/Decrease over 2004	194%	192%	188%	97%	94%

Table E.6 CO2 $25/Ton: Allowance Used Is CY 1990 Actual Beginning In FY 2008

VALUE MEASURE	Diversified IV	Diversified II	Diversifed III	Diversified I	Renewable
Comparative PVRR Ranking	1	2	3	4	5
Present Value Rev. Req't (20 Year $000)	**14,329,836**	**14,366,557**	**14,378,381**	**14,388,234**	**14,635,351**
Percent **Greater** Than Lowest NPV	0.000%	0.256%	0.339%	0.408%	2.132%
Incremental Net Variable Power Cost	12,391,068	11,869,978	12,011,005	11,854,102	12,444,134
Incremental Real Levelized Fixed Cost	1,748,542	2,306,354	2,177,151	2,343,907	2,000,991
DSM Real Levelized	190,225	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,077	2,831	2,644	2,643	2,237
Emissions (2004-2023 PVRR $000)	**1,079,398**	**1,504,403**	**1,392,752**	**1,515,740**	**1,015,588**
CO2 (thousand tons 2009-2023)	786,079	823,260	813,653	819,517	781,668
CO2 (% of cap)	115%	121%	120%	120%	115%
SO2 (thousand tons 2009-2023)	606	612	613	610	605
SO2 (% of cap)	58%	59%	59%	59%	58%
NOx (thousand tons 2009-2023)	995	1,003	1,003	1,001	993
NOx (% of cap)	97%	97%	97%	97%	96%
Hg (thousand tons 2009-2023)	0.0018	0.0029	0.0029	0.0032	0.0018
Hg (% of cap)	33%	53%	53%	58%	33%
Market Purchases (10 Year)					
PAC East (% of load)	0.2%	0.2%	0.2%	0.2%	0.2%
PAC East Average MW	14	13	13	13	12
PAC West (% of load)	1.3%	1.3%	1.4%	1.3%	1.3%
PAC West Average MW	99	98	101	98	100
Market Sales					
PAC East (% of owned Generation)	6.3%	6.5%	6.6%	6.5%	6.5%
PAC East Average MW	274	285	288	287	283
PAC West (% of owned Generation)	10.1%	10.0%	10.1%	10.3%	10.1%
PAC West Average MW	284	286	280	287	282
Unit Capacity Factors (2014)					
Existing Coal East	77.3%	75.3%	75.3%	75.1%	77.5%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.0%	2.0%	2.3%	2.2%	2.5%
IRP CCCT East	74.0%	66.6%	67.0%	66.7%	75.6%
IRP Coal East		91.0%	91.0%	91.0%	
IRP Peaker East	4.6%	3.8%	4.1%	3.8%	4.3%
Existing CCCT West	45.0%	40.7%	42.6%	42.0%	44.9%
Existing Coal West	84.9%	83.9%	84.0%	83.8%	84.8%
Existing Other West	90.9%	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	83.2%	83.9%	82.9%	81.8%	83.9%
IRP Peaker West	7.0%	8.5%	7.1%	6.7%	6.8%
East West Transfers (MWHs)					
2004 East-West Transfer	803,845	803,845	801,406	801,406	800,549
2014 East-West Transfer	612,659	81,482	91,715	66,610	653,388
Percent Increase/Decrease over 2004	76%	10%	11%	8%	82%
2004 West-East Transfer	1,900,881	1,900,881	1,904,206	1,904,206	1,905,072
2014 West-East Transfer	1,838,300	3,658,366	3,587,543	3,688,834	1,786,538
Percent Increase/Decrease over 2004	97%	192%	188%	194%	94%

Table E.7 CO2 $40/Ton: Allowance Used Is CY 1990 Actual Beginning In FY 2008

VALUE MEASURE	Diversified IV	Diversified II	Diversified III	Diversified I	Renewable
Comparative PVRR Ranking	*1*	*2*	*3*	*4*	*5*
Present Value Rev. Req't (20 Year $000)	**15,087,880**	**15,196,410**	**15,244,606**	**15,299,780**	**15,338,168**
Percent Greater Than Lowest NPV	0.000%	0.719%	1.039%	1.404%	1.659%
Incremental Net Variable Power Cost	13,149,113	12,699,831	12,877,229	12,765,648	13,146,952
Incremental Real Levelized Fixed Cost	1,748,542	2,306,354	2,177,151	2,343,907	2,000,991
DSM Real Levelized	190,225	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,077	2,831	2,644	2,643	2,237
Emissions (2004-2023 PVRR $000)	**1,101,062**	**1,760,703**	**1,599,257**	**1,785,622**	**997,070**
CO2 (thousand tons 2009-2023)	757,556	793,960	784,975	790,263	753,067
CO2 (% of cap)	111%	117%	115%	116%	111%
SO2 (thousand tons 2009-2023)	554	560	563	559	552
SO2 (% of cap)	53%	54%	54%	54%	53%
NOx (thousand tons 2009-2023)	936	943	945	941	933
NOx (% of cap)	91%	92%	92%	91%	91%
Hg (thousand tons 2009-2023)	0.0012	0.0023	0.0023	0.0026	0.0013
Hg (% of cap)	22%	42%	42%	47%	24%
Market Purchases (10 Year)					
PAC East (% of load)	0.3%	0.3%	0.3%	0.3%	0.2%
PAC East Average MW	21	20	19	19	18
PAC West (% of load)	1.4%	1.4%	1.4%	1.4%	1.4%
PAC West Average MW	105	103	105	103	105
Market Sales					
PAC East (% of owned Generation)	6.1%	6.3%	6.3%	6.3%	6.3%
PAC East Average MW	260	268	270	268	269
PAC West (% of owned Generation)	10.4%	10.3%	10.4%	10.6%	10.4%
PAC West Average MW	297	300	294	303	296
Unit Capacity Factors (2014)					
Existing Coal East	69.8%	67.8%	68.2%	68.0%	69.8%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.5%	2.3%	2.7%	2.6%	2.9%
IRP CCCT East	85.1%	81.8%	81.5%	81.0%	85.2%
IRP Coal East		91.0%	91.0%	91.0%	
IRP Peaker East	74.4%	5.0%	5.3%	5.2%	5.6%
Existing CCCT West	83.6%	81.7%	82.2%	82.4%	83.9%
Existing Coal West	79.3%	78.2%	78.9%	78.3%	79.1%
Existing Other West	90.9%	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	85.2%	87.9%	85.2%	84.9%	87.0%
IRP Peaker West	8.0%	9.3%	7.8%	7.4%	7.4%
East West Transfers (MWHs)					
2004 East-West Transfer	803,845	803,845	801,406	801,406	800,549
2014 East-West Transfer	612,659	81,482	91,715	66,610	653,388
Percent Increase/Decrease over 2004	76%	10%	11%	8%	82%
2004 West-East Transfer	1,900,881	1,900,881	1,904,206	1,904,206	1,905,072
2014 West-East Transfer	1,838,300	3,658,366	3,587,543	3,688,834	1,786,538
Percent Increase/Decrease over 2004	97%	192%	188%	194%	94%

Table E.8 Stress: Additional Wind Capacity Removed

VALUE MEASURE	Diversified I	Diversified II	Diversified III
Comparative PVRR Ranking	*1*	*2*	*3*
Present Value Rev. Req't (20 Year $000)	**12,380,827**	**12,407,945**	**12,434,973**
Incremental Net Variable Power Cost	9,846,681	9,911,352	10,067,583
Incremental Real Levelized Fixed Cost	2,343,921	2,306,368	2,177,165
DSM Real Levelized	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,644	2,831	2,643
Emissions (2004-2023 PVRR $000)	**106,978**	**111,873**	**70,965**
CO_2 (thousand tons 2009-2023)	865,365	868,696	857,646
CO_2 (% of cap)	107%	107%	106%
SO_2 (thousand tons 2009-2023)	661	662	662
SO_2 (% of cap)	64%	64%	64%
NO_x (thousand tons 2009-2023)	1,058	1,058	1,057
NO_x (% of cap)	103%	103%	103%
Hg (thousand tons 2009-2023)	0.0039	0.0036	0.0036
Hg (% of cap)	71%	66%	66%
Market Purchases (10 Year)			
PAC East (% of load)	0.2%	0.1%	0.1%
PAC East Average MW	12	10	10
PAC West (% of load)	1.2%	1.2%	1.3%
PAC West Average MW	92	91	96
Market Sales			
PAC East (% of owned Generation)	6.8%	6.6%	6.6%
PAC East Average MW	306	297	298
PAC West (% of owned Generation)	10.2%	10.0%	9.9%
PAC West Average MW	279	281	271
Unit Capacity Factors (2014)			
Existing Coal East	86.3%	86.4%	86.4%
Existing Other East	92.2%	92.2%	92.2%
Existing Peaker East	4.2%	4.0%	4.3%
IRP CCCT East	62.0%	61.0%	62.6%
IRP Coal East	91.0%	91.0%	91.0%
IRP Peaker East	6.3%	6.4%	6.4%
Existing CCCT West	51.0%	49.9%	51.9%
Existing Coal West	87.1%	87.2%	87.1%
Existing Other West	90.9%	90.9%	90.9%
IRP CCCT West	84.6%	85.7%	85.0%
IRP Peaker West	12.0%	14.8%	11.9%
East West Transfers			
2004 East-West Transfer	799,978	801,435	799,978
2014 East-West Transfer	1,004,300	1,012,008	1,085,245
Percent Increase/Decrease over 2004	126%	126%	136%
2004 West-East Transfer	1,901,936	1,899,981	1,901,936
2014 West-East Transfer	1,373,267	1,410,112	1,313,498
Percent Increase/Decrease over 2004	72%	74%	69%

Table E.9 Stress: $0 CO2 Tax, No Wind Capacity

VALUE MEASURE	Diversified I	Diversified II	Diversified III	Renewable II
Comparative PVRR Ranking	*1*	*2*	*3*	*4*
Present Value Rev. Req't (20 Year $000)	**12,086,798**	**12,122,491**	**12,190,984**	**12,518,355**
Incremental Net Variable Power Cost	9,552,653	9,625,898	9,823,594	10,260,032
Incremental Real Levelized Fixed Cost	2,343,921	2,306,368	2,177,165	2,012,765
DSM Real Levelized	190,225	190,225	190,225	245,558
Capital Cost (2002$-millions)	2,644	2,831	2,643	2,187
Emissions (2004-2023 PVRR $000)	**(85,268)**	**(85,543)**	**(86,881)**	**(54,760)**
CO2 (thousand tons 2009-2023)	875,455	878,577	867,057	823,381
CO2 (% of cap)	108%	109%	108%	102%
SO2 (thousand tons 2009-2023)	668	668	668	654
SO2 (% of cap)	64%	64%	64%	63%
NOx (thousand tons 2009-2023)	1,066	1,066	1,065	1,048
NOx (% of cap)	104%	104%	103%	102%
Hg (thousand tons 2009-2023)	0.0039	0.0036	0.0036	0.0024
Hg (% of cap)	71%	66%	66%	44%
Market Purchases (10 Year)				
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%
PAC East Average MW	11	10	9	9
PAC West (% of load)	1.1%	1.1%	1.1%	1.1%
PAC West Average MW	80	79	84	83
Market Sales				
PAC East (% of owned Generation)	7.6%	7.2%	7.7%	7.2%
PAC East Average MW	347	326	327	320
PAC West (% of owned Generation)	10.9%	10.8%	11.0%	10.7%
PAC West Average MW	304	308	296	299
Unit Capacity Factors (2014)				
Existing Coal East	88.1%	88.2%	88.1%	88.6%
Existing Other East	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	5.9%	5.6%	6.3%	6.5%
IRP CCCT East	62.3%	62.1%	63.1%	67.3%
IRP Coal East	91.0%	91.0%	91.0%	
IRP Peaker East	8.6%	8.5%	8.7%	12.0%
Existing CCCT West	55.7%	55.0%	56.9%	60.4%
Existing Coal West	87.3%	87.4%	87.3%	87.5%
Existing Other West	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	85.2%	85.8%	86.1%	86.0%
IRP Peaker West	18.2%	22.6%	18.6%	18.1%
East West Transfers				
2004 East-West Transfer	799,978	801,435	799,978	798,733
2014 East-West Transfer	1,018,437	1,049,608	1,094,800	923,484
Percent Increase/Decrease over 2004	127%	131%	137%	116%
2004 West-East Transfer	1,901,936	1,899,981	1,901,936	1,915,797
2014 West-East Transfer	1,323,241	1,359,365	1,276,948	1,489,085
Percent Increase/Decrease over 2004	70%	72%	67%	78%

Table E.10 Stress: Wind At 15% Capacity

VALUE MEASURE	Diversified I	Diversified II	Diversified III	New Technology
Comparative PVRR Ranking	*1*	*2*	*3*	*4*
Present Value Rev. Req't (20 Year $000)	**12,206,172**	**12,231,701**	**12,256,908**	**12,415,253**
Incremental Net Variable Power Cost	9,672,040	9,735,122	9,889,532	10,310,948
Incremental Real Levelized Fixed Cost	2,343,907	2,306,354	2,177,151	1,858,748
DSM Real Levelized	190,225	190,225	190,225	245,558
Capital Cost (2002$-millions)	2,643	2,831	2,644	2,108
Emissions (2004-2023 PVRR $000)	**57,368**	**66,783**	**26,509**	**(181,689)**
CO2 (thousand tons 2009-2023)	855,221	858,979	848,245	797,774
CO2 (% of cap)	106%	106%	106%	99%
SO2 (thousand tons 2009-2023)	656	658	657	639
SO2 (% of cap)	63%	63%	63%	62%
NOx (thousand tons 2009-2023)	1,052	1,054	1,053	1,031
NOx (% of cap)	102%	102%	102%	100%
Hg (thousand tons 2009-2023)	0.0038	0.0036	0.0036	0.0024
Hg (% of cap)	69%	66%	66%	44%
Market Purchases (10 Year)				
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%
PAC East Average MW	10	9	9	9
PAC West (% of load)	1.2%	1.2%	1.2%	1.1%
PAC West Average MW	89	89	93	80
Market Sales				
PAC East (% of owned Generation)	7.0%	6.8%	7.1%	6.9%
PAC East Average MW	320	310	312	307
PAC West (% of owned Generation)	10.3%	10.1%	10.3%	10.9%
PAC West Average MW	290	290	281	305
Unit Capacity Factors (2014)				
Existing Coal East	85.1%	85.3%	85.0%	85.2%
Existing Other East	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.6%	3.4%	3.9%	3.6%
IRP CCCT East	52.3%	51.8%	52.0%	51.2%
IRP Coal East	91.0%	91.0%	91.0%	
IRP Peaker East	5.1%	4.9%	5.4%	6.7%
Existing CCCT West	40.1%	37.5%	41.1%	64.1%
Existing Coal West	86.5%	86.7%	86.6%	36.6%
Existing Other West	90.9%	90.9%	90.9%	86.3%
IRP CCCT West	80.3%	80.4%	81.4%	86.3%
IRP Peaker West	10.5%	13.2%	11.2%	94.0%
East West Transfers (MWHs)				
2004 East-West Transfer	799,978	801,435	799,978	798,733
2014 East-West Transfer	1,196,939	1,218,402	1,229,442	1,046,767
Percent Increase/Decrease over 2004	150%	152%	154%	131%
2004 West-East Transfer	1,901,936	1,899,981	1,901,936	1,915,797
2014 West-East Transfer	1,237,832	1,208,774	1,179,098	1,314,900
Percent Increase/Decrease over 2004	65%	64%	62%	69%

Table E.11 Stress: Wind Install One Year Early

VALUE MEASURE	Diversified I	Diversified II	Diversified III
Comparative PVRR Ranking	*1*	*2*	*3*
Present Value Rev. Req't (20 Year $000)	**12,327,592**	**12,351,937**	**12,372,039**
Incremental Net Variable Power Cost	9,797,842	9,855,344	10,008,405
Incremental Real Levelized Fixed Cost	2,339,524	2,306,368	2,173,409
DSM Real Levelized	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,643	2,831	2,644
Emissions (2004-2023 PVRR $000)	**14,410**	**27,338**	**(13,604)**
CO2 (thousand tons 2009-2023)	846,783	850,955	840,220
CO2 (% of cap)	105%	105%	104%
SO2 (thousand tons 2009-2023)	651	654	653
SO2 (% of cap)	63%	63%	63%
NOx (thousand tons 2009-2023)	1,045	1,049	1,047
NOx (% of cap)	102%	102%	102%
Hg (thousand tons 2009-2023)	0.0037	0.0036	0.0036
Hg (% of cap)	67%	66%	66%
Market Purchases (10 Year)			
PAC East (% of load)	0.1%	0.1%	0.1%
PAC East Average MW	10	8	8
PAC West (% of load)	1.0%	1.0%	1.1%
PAC West Average MW	77	76	80
Market Sales			
PAC East (% of owned Generation)	7.2%	7.0%	7.1%
PAC East Average MW	327	318	320
PAC West (% of owned Generation)	11.2%	10.9%	10.9%
PAC West Average MW	309	310	302
Unit Capacity Factors (2014)			
Existing Coal East	84.3%	84.6%	84.2%
Existing Other East	92.2%	92.2%	92.2%
Existing Peaker East	3.3%	3.0%	3.5%
IRP CCCT East	47.8%	47.0%	47.5%
IRP Coal East	91.0%	91.0%	91.0%
IRP Peaker East	4.6%	4.5%	5.0%
Existing CCCT West	34.2%	31.5%	35.2%
Existing Coal West	86.0%	86.2%	86.1%
Existing Other West	90.9%	90.9%	90.9%
IRP CCCT West	77.4%	77.2%	78.5%
IRP Peaker West	9.0%	11.9%	10.1%
East West Transfers (MWHs)			
2004 East-West Transfer	799,978	801,435	799,978
2014 East-West Transfer	1,077,393	1,124,739	1,083,438
Percent Increase/Decrease over 2004	135%	140%	135%
2004 West-East Transfer	1,901,936	1,899,981	1,901,936
2014 West-East Transfer	1,303,125	1,332,926	1,293,016
Percent Increase/Decrease over 2004	69%	70%	68%

Table E.12 Stress: Peakers to CCCTs and IGCC in 2012

VALUE MEASURE	Diversified I Base	Diversified I Pkrs to CCCTs	Diversified III Base	Diversified III Hunter 4 to IGCC
Present Value Rev. Req't (20 Year $000)	**12,313,159**	**12,338,104**	**12,360,185**	**12,537,042**
% change from base		**0.20%**		**1.43%**
Incremental Net Variable Power Cost	9,779,027	9,562,638	9,992,809	10,222,845
Incremental Real Levelized Fixed Cost	2,343,907	2,585,241	2,177,151	2,123,972
DSM Real Levelized	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,643	3,094	2,644	2,626
Emissions (2004-2023 PVRR $000)	**21,750**	**52,970**	**(7,237)**	**(80,888)**
CO2 (thousand tons 2009-2023)	847,919	858,938	841,248	822,675
CO2 (% of cap)	105%	106%	104%	105%
SO2 (thousand tons 2009-2023)	652	649	654	650
SO2 (% of cap)	63%	62%	63%	63%
NOx (thousand tons 2009-2023)	1,046	1,043	1,047	1,038
NOx (% of cap)	102%	101%	102%	101%
Hg (thousand tons 2009-2023)	0.0038	0.0037	0.0036	0.0036
Hg (% of cap)	69%	67%	66%	66%
Market Purchases (10 Year)				
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%
PAC East Average MW	10	8	9	9
PAC West (% of load)	1.1%	0.9%	1.1%	1.1%
PAC West Average MW	80	66	83	83
Market Sales				
PAC East (% of owned Generation)	7.1%	7.4%	7.0%	7.2%
PAC East Average MW	323	339	316	310
PAC West (% of owned Generation)	11.0%	12.2%	10.7%	11.0%
PAC West Average MW	304	344	296	295
Unit Capacity Factors (2014)				
Existing Coal East	84.3%	84.2%	84.2%	86.0%
Existing Other East	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.3%	1.4%	3.5%	3.7%
IRP CCCT East	47.8%	37.2%	47.5%	56.7%
IRP Coal East	91.0%	91.0%	91.0%	71.3%
IRP Peaker East	4.6%	3.4%	5.0%	5.3%
Existing CCCT West	34.2%	11.6%	35.2%	36.1%
Existing Coal West	86.0%	85.3%	86.1%	86.7%
Existing Other West	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	77.4%	69.9%	78.5%	80.9%
IRP Peaker West	9.0%	10.1%	10.1%	10.2%
East West Transfers (MWHs)				
2004 East-West Transfer	799,978	799,978	799,978	803,417
2014 East-West Transfer	1,077,393	900,677	1,083,438	946,502
Percent Increase/Decrease over 2004	135%	113%	135%	118%
2004 West-East Transfer	1,901,936	1,901,936	1,901,936	1,902,703
2014 West-East Transfer	1,303,125	1,449,643	1,293,016	1,410,333
Percent Increase/Decrease over 2004	69%	76%	68%	74%

Table E.13 Stress: Timing Variation of Large East Resources

	DP1 2008 2009 2012				DP3 2007 2009 2012	
VALUE MEASURE	**Base**	**V2**	**V3**	**V4**	**Base**	**V2**
	HGM	GHM	GMH	GMM	GMH	GHM
Comparative PVRR Ranking	*1*	*3*	*2*	*6*	*4*	*5*
Present Value Rev. Req't (20 Year $000)	**12,313,159**	**12,325,424**	**12,317,132**	**12,395,185**	**12,360,185**	**12,370,745**
Percent Greater Than Lowest NPV	0.000%	0.100%	0.032%	0.666%	0.382%	0.468%
Incremental Net Variable Power Cost	9,779,027	9,844,373	9,972,388	10,456,417	9,992,809	9,860,009
Incremental Real Levelized Fixed Cost	2,343,907	2,290,826	2,154,519	1,748,542	2,177,151	2,320,511
DSM Real Levelized	190,225	190,225	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,643	2,643	2,644	2,077	2,644	2,644
Emissions (2004-2023 PVRR $000)	**21,750**	**22,140**	**(2,925)**	**(122,127)**	**(7,237)**	**19,020**
CO2 (thousand tons 2009-2023)	847,919	847,920	842,436	811,477	841,248	846,882
CO2 (% of cap)	105%	105%	104%	100%	104%	105%
SO2 (thousand tons 2009-2023)	652	652	654	645	654	652
SO2 (% of cap)	63%	63%	63%	62%	63%	63%
NOx (thousand tons 2009-2023)	1,046	1,046	1,048	1,036	1,047	1,047
NOx (% of cap)	102%	102%	102%	101%	102%	102%
Hg (thousand tons 2009-2023)	0.0038	0.0038	0.0036	0.0024	0.0036	0.0038
Hg (% of cap)	69%	69%	66%	44%	66%	69%
Market Purchases (10 Year)						
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
PAC East Average MW	10	10	10	11	9	9
PAC West (% of load)	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%
PAC West Average MW	80	80	80	80	83	83
Market Sales						
PAC East (% of owned Generation)	7.1%	7.1%	6.9%	6.7%	7.0%	7.2%
PAC East Average MW	323	320	309	300	316	327
PAC West (% of owned Generation)	11.0%	10.9%	10.9%	10.8%	10.7%	10.8%
PAC West Average MW	304	303	305	304	296	296
Unit Capacity Factors (2014)						
Existing Coal East	84.3%	84.3%	84.3%	86.2%	84.2%	84.2%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.3%	3.3%	3.3%	4.2%	3.5%	3.5%
IRP CCCT East	47.8%	47.8%	47.8%	63.3%	47.5%	47.5%
IRP Coal East	91.0%	91.0%	91.0%			
IRP Peaker East	4.6%	4.6%	4.6%	5.5%	5.0%	5.0%
Existing CCCT West	34.2%	34.2%	34.2%	37.8%	58.8%	96.6%
Existing Coal West	86.0%	86.0%	86.0%	86.9%	35.2%	86.1%
Existing Other West	90.9%	90.9%	90.9%	90.9%	86.1%	90.9%
IRP CCCT West	77.4%	77.4%	77.4%	81.8%	78.5%	78.5%
IRP Peaker West	9.0%	9.0%	9.0%	10.1%	10.1%	10.1%
East West Transfers (MWHs)						
2004 East-West Transfer	799,978	799,978	799,978	801,435	799,978	799,978
2014 East-West Transfer	1,077,393	1,077,393	1,077,393	766,831	1,083,438	1,083,438
Percent Increase/Decrease over 2004	135%	135%	135%	96%	135%	135%
2004 West-East Transfer	1,901,936	1,901,936	1,901,936	1,899,981	1,901,936	1,901,936
2014 West-East Transfer	1,303,125	1,303,125	1,303,125	1,588,166	1,293,016	1,293,016
Percent Increase/Decrease over 2004	69%	69%	69%	84%	68%	68%

Table E.14 Stress: Hydro Loss of Capacity

VALUE MEASURE	Diversified I	Diversified II	Diversified III
Comparative PVRR Ranking	*1*	*2*	*3*
Present Value Rev. Req't (20 Year $000)	**12,920,746**	**12,945,841**	**12,967,725**
Incremental Net Variable Power Cost	10,238,876	10,304,970	10,452,610
Incremental Real Levelized Fixed Cost	2,491,645	2,450,645	2,324,890
DSM Real Levelized	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,760	2,947	2,761
Emissions (2004-2023 PVRR $000)	**44,098**	**52,706**	**12,981**
CO2 (thousand tons 2009-2023)	852,733	856,345	845,774
CO2 (% of cap)	105%	106%	105%
SO2 (thousand tons 2009-2023)	654	656	655
SO2 (% of cap)	63%	63%	63%
NOx (thousand tons 2009-2023)	1,049	1,051	1,049
NOx (% of cap)	102%	102%	102%
Hg (thousand tons 2009-2023)	0.0038	0.0036	0.0036
Hg (% of cap)	69%	66%	66%
Market Purchases (10 Year)			
PAC East (% of load)	0.1%	0.1%	0.1%
PAC East Average MW	11	10	9
PAC West (% of load)	1.3%	1.2%	1.3%
PAC West Average MW	93	93	97
Market Sales			
PAC East (% of owned Generation)	7.0%	6.8%	7.0%
PAC East Average MW	318	307	309
PAC West (% of owned Generation)	10.3%	10.0%	10.3%
PAC West Average MW	279	279	271
Unit Capacity Factors (2014)			
Existing Coal East	84.5%	84.8%	84.9%
Existing Other East	92.2%	92.2%	92.2%
Existing Peaker East	3.6%	3.3%	4.0%
IRP CCCT East	50.3%	50.0%	50.7%
IRP Coal East	90.9%	91.0%	91.0%
IRP Peaker East	5.0%	4.7%	5.1%
Existing CCCT West	39.0%	37.9%	39.8%
Existing Coal West	86.3%	86.4%	86.3%
Existing Other West	90.9%	90.9%	90.9%
IRP CCCT West	81.0%	79.9%	81.8%
IRP Peaker West	10.9%	13.6%	11.5%
East West Transfers (MWHs)			
2004 East-West Transfer	799,978	801,435	799,978
2014 East-West Transfer	1,196,939	1,218,402	1,229,442
Percent Increase/Decrease over 2004	150%	152%	154%
2004 West-East Transfer	1,901,936	1,899,981	1,901,936
2014 West-East Transfer	1,237,832	1,208,774	1,179,098
Percent Increase/Decrease over 2004	65%	64%	62%

Table E.15 Stress: SB1149 Loss Of Load

VALUE MEASURE	Diversified I	Diversified II	Diversified III
Comparative PVRR Ranking	*1*	*2*	*3*
Present Value Rev. Req't (20 Year $000)	**10,534,056**	**10,549,642**	**10,557,592**
Incremental Net Variable Power Cost	8,347,855	8,400,995	8,538,614
Incremental Real Levelized Fixed Cost	1,995,975	1,958,422	1,828,753
DSM Real Levelized	190,225	190,225	190,225
Capital Cost (2002$-millions)	2,322	2,510	2,323
Emissions (2004-2023 PVRR $000)	**(65,703)**	**(47,738)**	**(89,889)**
CO2 (thousand tons 2009-2023)	827,651	832,597	822,021
CO2 (% of cap)	102%	103%	102%
SO2 (thousand tons 2009-2023)	648	652	650
SO2 (% of cap)	62%	63%	62%
NOx (thousand tons 2009-2023)	1,040	1,045	1,041
NOx (% of cap)	101%	102%	101%
Hg (thousand tons 2009-2023)	0.0037	0.0036	0.0035
Hg (% of cap)	67%	66%	64%
Market Purchases (10 Year)			
PAC East (% of load)	0.1%	0.1%	0.1%
PAC East Average MW	9	9	8
PAC West (% of load)	0.7%	0.7%	0.7%
PAC West Average MW	49	47	48
Market Sales			
PAC East (% of owned Generation)	7.4%	7.2%	7.4%
PAC East Average MW	332	320	323
PAC West (% of owned Generation)	14.4%	14.0%	14.3%
PAC West Average MW	363	365	362
Unit Capacity Factors (2014)			
Existing Coal East	83.8%	84.1%	83.8%
Existing Other East	92.2%	92.2%	92.2%
Existing Peaker East	3.1%	3.0%	3.0%
IRP CCCT East	44.2%	44.1%	44.2%
IRP Coal East	91.0%	91.0%	91.0%
IRP Peaker East	4.6%	4.5%	4.5%
Existing CCCT West	24.1%	24.7%	26.3%
Existing Coal West	84.9%	85.5%	85.0%
Existing Other West	90.9%	90.9%	90.9%
IRP CCCT West	66.4%	66.9%	64.5%
IRP Peaker West	8.1%	9.8%	8.1%
East West Transfers			
2004 East-West Transfer	773,961	774,118	773,961
2014 East-West Transfer	801,196	897,717	785,202
Percent Increase/Decrease over 2004	104%	116%	101%
2004 West-East Transfer	2,042,596	2,043,992	2,042,596
2014 West-East Transfer	1,601,109	1,525,223	1,592,064
Percent Increase/Decrease over 2004	78%	75%	78%

Table E.16 Stress: Decrement DSM - Diversified I

VALUE MEASURE	Base	> $40/MWh	1% 150	1% 300	10% 150
Present Value Rev. Req't (20 Year $000)	**12,313,159**	**12,272,972**	**12,238,010**	**12,232,334**	**12,197,848**
Percent Greater Than Lowest NPV	8.769%	8.414%	8.105%	8.055%	7.750%
Incremental Net Variable Power Cost	8,349,474	8,309,288	8,346,167	8,340,491	8,365,197
Incremental Real Levelized Fixed Cost	3,773,460	3,773,460	3,701,618	3,701,618	3,642,425
DSM Real Levelized	190,225	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	4,158	4,158	4,102	4,102	4,004
Emissions (2004-2023 PVRR $000)	**21,750**	**18,896**	**21,627**	**21,301**	**19,256**
CO2 (thousand tons 2009-2023)	847,919	847,473	847,812	847,732	845,298
CO2 (% of cap)	105%	105%	105%	105%	105%
SO2 (thousand tons 2009-2023)	652	652	652	652	655
SO2 (% of cap)	63%	63%	63%	63%	63%
NOx (thousand tons 2009-2023)	1,046	1,046	1,047	1,047	1,050
NOx (% of cap)	102%	102%	102%	102%	102%
Hg (thousand tons 2009-2023)	0.0038	0.0038	0.0038	0.0038	0.0039
Hg (% of cap)	69%	69%	69%	69%	71%
Market Purchases (10 Year)					
PAC East (% of load)	0.1%	0.1%	0.1%	0.1%	0.1%
PAC East Average MW	10	9	10	10	11
PAC West (% of load)	1.1%	1.1%	1.1%	1.1%	1.1%
PAC West Average MW	80	80	80	80	79
Market Sales					
PAC East (% of owned Generation)	7.1%	7.2%	7.1%	7.1%	7.0%
PAC East Average MW	323	326	324	324	315
PAC West (% of owned Generation)	11.0%	11.1%	11.0%	11.0%	11.0%
PAC West Average MW	304	305	304	304	307
Unit Capacity Factors (2014)					
Existing Coal East	84.3%	84.1%	84.4%	84.3%	84.8%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	3.3%	3.1%	3.0%	3.2%	4.4%
IRP CCCT East	47.8%	47.7%	46.9%	46.9%	50.0%
IRP Coal East	91.0%	91.0%	91.0%	91.0%	91.0%
IRP Peaker East	4.6%	4.6%	4.7%	4.6%	5.8%
Existing CCCT West	34.2%	32.5%	32.9%	32.8%	38.4%
Existing Coal West	86.0%	86.0%	86.0%	86.0%	86.0%
Existing Other West	90.9%	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	77.4%	78.0%	78.1%	77.7%	77.7%
IRP Peaker West	9.0%	9.1%	9.5%	9.3%	9.8%
East West Transfers					
2004 East-West Transfer	800	806	800	800	800
2014 East-West Transfer	1,077	1,097	1,046	1,045	936
Percent Increase/Decrease over 2004	135%	136%	131%	131%	117%
2004 West-East Transfer	1,902	1,938	1,902	1,902	1,902
2014 West-East Transfer	1,303	1,293	1,339	1,321	1,506
Percent Increase/Decrease over 2004	69%	67%	70%	69%	79%

Table E.16 Stress: Decrement DSM - Diversified I (Continued)

VALUE MEASURE	20% 300	40% 150	60% 300	10MW PV	10MW 60% ETO
Present Value Rev. Req't (20 Year $000)	**11,998,743**	**11,876,743**	**11,320,508**	**12,305,234**	**12,279,601**
Percent Greater Than Lowest NPV	5.991%	4.914%	0.000%	8.699%	8.472%
Incremental Net Variable Power Cost	8,304,624	8,139,648	7,781,609	8,341,549	8,315,916
Incremental Real Levelized Fixed Cost	3,503,894	3,546,870	3,348,673	3,773,460	3,773,460
DSM Real Levelized	190,225	190,225	190,225	190,225	190,225
Capital Cost (2002$-millions)	3,821	3,867	3,669	4,158	4,158
Emissions (2004-2023 PVRR $000)	**(4,217)**	**(24,573)**	**(65,572)**	**21,517**	**20,404**
CO2 (thousand tons 2009-2023)	838,913	835,181	827,236	847,873	847,631
CO2 (% of cap)	104%	103%	102%	105%	105%
SO2 (thousand tons 2009-2023)	655	652	647	652	652
SO2 (% of cap)	63%	63%	62%	63%	63%
NOx (thousand tons 2009-2023)	1,049	1,045	1,038	1,046	1,046
NOx (% of cap)	102%	102%	101%	102%	102%
Hg (thousand tons 2009-2023)	0.0039	0.0038	0.0037	0.0038	0.0038
Hg (% of cap)	71%	69%	67%	69%	69%
Market Purchases (10 Year)					
PAC East (% of load)	0.2%	0.2%	0.2%	0.1%	0.1%
PAC East Average MW	12	11	11	10	10
PAC West (% of load)	1.1%	1.0%	1.0%	1.1%	1.1%
PAC West Average MW	78	77	75	80	79
Market Sales					
PAC East (% of owned Generation)	6.8%	6.9%	7.2%	7.1%	7.1%
PAC East Average MW	303	307	316	324	324
PAC West (% of owned Generation)	11.1%	11.2%	11.4%	11.0%	11.1%
PAC West Average MW	311	311	315	305	306
Unit Capacity Factors (2014)					
Existing Coal East	84.5%	84.0%	83.2%	84.2%	84.1%
Existing Other East	92.2%	92.2%	92.2%	92.2%	92.2%
Existing Peaker East	4.7%	4.9%	4.1%	3.3%	3.4%
IRP CCCT East	50.9%	47.6%	40.3%	48.0%	48.1%
IRP Coal East	91.0%	91.0%	91.0%	91.0%	91.0%
IRP Peaker East	2.8%	2.7%	2.9%	4.8%	4.8%
Existing CCCT West	43.0%	40.9%	35.0%	32.3%	32.3%
Existing Coal West	85.8%	85.5%	85.0%	86.0%	86.0%
Existing Other West	90.9%	90.9%	90.9%	90.9%	90.9%
IRP CCCT West	77.8%	76.4%	75.4%	77.8%	76.8%
IRP Peaker West	9.7%	9.6%	9.0%	9.5%	9.3%
East West Transfers					
2004 East-West Transfer	800	800	800	800	800
2014 East-West Transfer	902	978	1,148	1,086	1,068
Percent Increase/Decrease over 2004	113%	122%	144%	136%	133%
2004 West-East Transfer	1,904	1,904	1,904	1,902	1,902
2014 West-East Transfer	1,678	1,616	1,479	1,311	1,296
Percent Increase/Decrease over 2004	88%	85%	78%	69%	68%

Table E.17 Real Levelized Versus Nominal PV Versus Constant

Comparison Of Present Value Versus Constant Dollar Results And Capital Costs Calculated Using Real Levelized Versus Nominal Revenue Requirements.

Results Based On Model Runs Prepared For Final Report.
(PVRR Results Are In Millions Of Dollars).

	Present Value Results Discounted at WACC		Constant Dollar Results Discounted at Escalation Rate		Constant Dollar Results 20-Yr Average $/MWh	
Discount Rate	w/ real levelized 4/1/2003 PVRR 7.5%	w/ nominal (1) 4/1/2003 PVRR 7.5%	w/ real levelized 4/1/2003 PVRR 2.5%	w/ nominal (1) 4/1/2003 PVRR 2.5%	w/ real levelized 4/1/2003 PVRR 2.5%	w/ nominal (1) 4/1/2003 PVRR 2.5%
Diversified I	12,313	12,895	21,684	22,369	$15.26	$15.74
Diversified II	12,338	12,940	21,716	22,474	$15.28	$15.82
Diversified III	12,360	12,926	21,757	22,457	$15.31	$15.80
Diversified IV	12,395	12,871	21,855	22,405	$15.38	$15.77
Alternative Technology II	12,559	12,974	22,180	22,583	$15.74	$16.03
Coal/Gas III	12,651	13,141	22,300	22,955	$15.69	$16.15
PacifiCorp Build – I	12,679	13,189	22,332	23,060	$15.71	$16.22
Gas/Coal I	12,706	13,180	22,386	23,056	$15.75	$16.22
Gas/Coal II	12,715	13,188	22,396	23,064	$15.76	$16.23
Gas/Coal III	12,743	13,216	22,435	23,091	$15.78	$16.24
PacifiCorp Build II	12,748	13,258	22,477	23,208	$15.81	$16.33
Peakers	12,759	13,215	22,489	23,134	$15.82	$16.27
Renewable	12,767	13,235	22,569	23,062	$15.88	$16.23
Alternative Technology I	12,770	13,081	22,475	22,620	$15.94	$16.05
All Gas II	12,865	13,251	22,706	23,219	$15.97	$16.33
Wyoming Coal	12,868	13,360	22,694	23,394	$15.96	$16.46
All Gas I	12,889	13,264	22,739	23,225	$16.00	$16.34
Coal/Gas II	12,908	13,317	22,771	23,264	$16.02	$16.36
Coal/Gas I	12,910	13,368	22,759	23,336	$16.01	$16.41
Transmission - 1000MW DC	13,018	13,737	22,969	24,012	$16.15	$16.89
Transmission - 2000MW DC	13,218	14,022	23,357	24,546	$16.43	$17.26
Transmission - Asset Build Market	13,221	13,662	23,420	24,034	$16.48	$16.91
Coal/Gas III - 10%	12,358	12,819	21,808	22,451	$15.35	$15.80
Gas/Coal I - 10%	12,376	12,807	21,814	22,466	$15.34	$15.80
PacifiCorp Build II - 10%	12,531	13,019	22,129	22,875	$15.56	$16.09
All Gas II - 10%	12,576	12,934	22,220	22,723	$15.63	$15.99

Percent above Least Cost Portfolio **Discount Rate**	w/ real levelized 4/1/2003 PVRR 7.5%	w/ nominal (1) 4/1/2003 PVRR 7.5%	w/ real levelized 4/1/2003 PVRR 2.5%	w/ nominal (1) 4/1/2003 PVRR 2.5%	w/ real levelized 4/1/2003 PVRR 2.5%	w/ nominal (1) 4/1/2003 PVRR 2.5%
Diversified I	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%
Diversified II	0.2%	1.0%	0.1%	0.5%	0.1%	0.5%
Diversified III	0.4%	0.9%	0.3%	0.4%	0.3%	0.4%
Diversified IV	0.7%	0.5%	0.8%	0.2%	0.8%	0.1%
Alternative Technology II	2.0%	1.3%	2.3%	1.0%	3.1%	1.8%
Coal/Gas III	2.7%	2.6%	2.8%	2.6%	2.8%	2.6%
PacifiCorp Build – I	3.0%	3.0%	3.0%	3.1%	2.9%	3.0%
Gas/Coal I	3.2%	2.9%	3.2%	3.1%	3.2%	3.0%
Gas/Coal II	3.3%	3.0%	3.3%	3.1%	3.2%	3.1%
Gas/Coal III	3.5%	3.2%	3.5%	3.2%	3.4%	3.2%
PacifiCorp Build II	3.5%	3.5%	3.7%	3.7%	3.6%	3.7%
Peakers	3.6%	3.2%	3.7%	3.4%	3.6%	3.4%
Renewable	3.7%	3.3%	4.1%	3.1%	4.1%	3.1%
Alternative Technology I	3.7%	2.1%	3.6%	1.1%	4.5%	1.9%
All Gas II	4.5%	3.5%	4.7%	3.8%	4.7%	3.7%
Wyoming Coal	4.5%	4.3%	4.7%	4.6%	4.6%	4.5%
All Gas I	4.7%	3.6%	4.9%	3.8%	4.8%	3.8%
Coal/Gas II	4.8%	4.0%	5.0%	4.0%	4.9%	3.9%
Coal/Gas I	4.8%	4.4%	5.0%	4.3%	4.9%	4.3%
Transmission - 1000MW DC	5.7%	7.3%	5.9%	7.3%	5.8%	7.3%
Transmission - 2000MW DC	7.3%	9.5%	7.7%	9.7%	7.6%	9.6%
Transmission - Asset Build Market	7.4%	6.7%	8.0%	7.4%	8.0%	7.4%
Coal/Gas III - 10%	0.4%	0.1%	0.6%	0.4%	0.5%	0.3%
Gas/Coal I - 10%	0.5%	0.0%	0.6%	0.4%	0.5%	0.4%
PacifiCorp Build II - 10%	1.8%	1.7%	2.1%	2.3%	2.0%	2.2%
All Gas II - 10%	2.1%	1.0%	2.5%	1.6%	2.4%	1.5%

1. Capital fixed cost w/nominal revenue requirements are calculated under the traditional rate-making methodology. These values do not include an adjustment for life end-effects. An adjustment would be necessary using nominal capital revenue requirement because the depreciation lives of the new resources extend beyond the 20-year study period

APPENDIX F – PORTFOLIO LOAD AND RESOURCE BALANCES

Table F.1 Load Resource Capacity Report

Annual Coincident Peak Hour

Fiscal Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total System Peak Obligation										
Load East	5,267	5,354	5,468	5,621	5,733	5,875	6,000	6,069	6,267	6,333
Load West	3,711	3,831	3,727	3,792	3,843	3,290	3,338	3,459	3,456	3,572
Thermal East	5,209	5,209	5,209	5,203	5,187	4,944	4,944	4,943	4,767	4,661
Thermal West	2,376	2,376	2,376	2,376	2,376	2,129	2,129	2,129	2,129	2,129
Hydro East	78	78	78	78	78	82	82	78	78	78
Hydro West	1,170	1,231	1,230	1,143	1,147	1,180	1,180	1,149	1,145	952
Interruptible	70	70	70	70	70	70	70	70	70	70
Long Term Sale East	(1,150)	(1,125)	(1,117)	(1,117)	(867)	(865)	(792)	(792)	(792)	(792)
Long Term Sale West	(871)	(686)	(433)	(433)	(363)	(373)	(365)	(355)	(345)	(290)
Long Term Purchase East	450	450	460	481	303	343	366	365	389	413
Long Term Purchase West	955	955	791	812	527	258	231	193	217	183
BPA Peaking	750	575	575	575	575	575	575	575	0	0
System Load	8,978	9,185	9,195	9,413	9,576	9,165	9,338	9,528	9,723	9,905
plus Firm Sales	2,021	1,811	1,550	1,550	1,230	1,238	1,157	1,147	1,137	1,082
less Interruptible	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
less Firm Purchases	(1,405)	(1,405)	(1,251)	(1,293)	(830)	(601)	(597)	(558)	(606)	(596)
Less BPA	(750)	(575)	(575)	(575)	(575)	(575)	(575)	(575)	0	0
Net Firm Obligations	8,774	8,946	8,849	9,025	9,331	9,157	9,253	9,472	10,184	10,321
Total Resources	8,833	8,894	8,893	8,800	8,788	8,335	8,335	8,299	8,119	7,820
Net Reserves w/o Additions	59	(52)	44	(225)	(543)	(822)	(918)	(1,173)	(2,065)	(2,501)
Desired Planning Reserves 15%	1,316	1,342	1,327	1,354	1,400	1,374	1,388	1,421	1,528	1,548
Desired Planning Reserves 10%	877	895	885	903	933	916	925	947	1,018	1,032
Capacity Additions Required 15%	1,257	1,394	1,283	1,579	1,943	2,196	2,306	2,594	3,593	4,049
Capacity Additions Required 10%	818	947	841	1,128	1,476	1,738	1,843	2,120	3,083	3,533
Portfolio:					**Gas/Coal I**					
Portfolio Resource Additions	790	834	1,370	1,723	1,769	2,306	2,367	2,630	3,597	4,152
Net Reserves (MW)	849	782	1,414	1,498	1,226	1,484	1,449	1,457	1,532	1,651
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	16.6%	13.1%	16.2%	15.7%	15.4%	15.0%	16.0%
Portfolio:					**Gas/Coal I - 10%**					
Portfolio Resource Additions	790	834	940	1,043	1,599	1,856	1,917	2,180	3,117	3,652
Net Reserves (MW)	849	782	984	818	1,056	1,034	999	1,007	1,052	1,151
Net Reserves % of Total Obligation	9.7%	8.7%	11.1%	9.1%	11.3%	11.3%	10.8%	10.6%	10.3%	11.2%
Portfolio:					**Alternative Technology I**					
Portfolio Resource Additions	792	844	1,828	1,796	2,162	2,254	2,375	2,988	3,875	3,965
Net Reserves (MW)	851	792	1,872	1,571	1,619	1,432	1,457	1,815	1,810	1,464
Net Reserves % of Total Obligation	9.7%	8.9%	21.2%	17.4%	17.3%	15.6%	15.7%	19.2%	17.8%	14.2%

Table F.1 Load Resource Capacity Report (Continued)

Portfolio:	**Gas/Coal II**									
Portfolio Resource Additions	790	834	1,370	1,693	1,739	2,306	2,367	2,630	3,667	4,152
Net Reserves (MW)	849	782	1,414	1,468	1,196	1,484	1,449	1,457	1,602	1,651
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	16.3%	12.8%	16.2%	15.7%	15.4%	15.7%	16.0%
Portfolio:	**Wyoming Coal**									
Portfolio Resource Additions	790	834	1,370	1,693	1,739	2,306	2,367	2,630	3,622	3,907
Net Reserves (MW)	849	782	1,414	1,468	1,196	1,484	1,449	1,457	1,557	1,406
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	16.3%	12.8%	16.2%	15.7%	15.4%	15.3%	13.6%
Portfolio:	**All Gas I**									
Portfolio Resource Additions	790	834	1,370	1,723	1,769	2,306	2,367	2,630	3,602	4,157
Net Reserves (MW)	849	782	1,414	1,498	1,226	1,484	1,449	1,457	1,537	1,656
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	16.6%	13.1%	16.2%	15.7%	15.4%	15.1%	16.0%
Portfolio:	**Peakers**									
Portfolio Resource Additions	790	834	1,370	1,653	1,699	2,266	2,327	2,590	3,627	4,212
Net Reserves (MW)	849	782	1,414	1,428	1,156	1,444	1,409	1,417	1,562	1,711
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	15.8%	12.4%	15.8%	15.2%	15.0%	15.3%	16.6%
Portfolio:	**PacifiCorp Build – I**									
Portfolio Resource Additions	790	834	1,370	1,753	1,799	2,366	2,427	2,745	3,682	4,167
Net Reserves (MW)	849	782	1,414	1,528	1,256	1,544	1,509	1,572	1,617	1,666
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	16.9%	13.5%	16.9%	16.3%	16.6%	15.9%	16.1%
Portfolio:	**Coal/Gas I**									
Portfolio Resource Additions	790	834	1,320	1,593	2,214	2,271	2,332	2,595	3,667	4,152
Net Reserves (MW)	849	782	1,364	1,368	1,671	1,449	1,414	1,422	1,602	1,651
Net Reserves % of Total Obligation	9.7%	8.7%	15.4%	15.2%	17.9%	15.8%	15.3%	15.0%	15.7%	16.0%
Portfolio:	**Gas/Coal III**									
Portfolio Resource Additions	790	834	1,370	1,693	2,249	2,306	2,367	2,630	3,897	4,152
Net Reserves (MW)	849	782	1,414	1,468	1,706	1,484	1,449	1,457	1,832	1,651
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	16.3%	18.3%	16.2%	15.7%	15.4%	18.0%	16.0%
Portfolio:	**Coal/Gas II**									
Portfolio Resource Additions	790	834	1,320	1,618	2,249	2,306	2,367	2,630	3,667	4,152
Net Reserves (MW)	849	782	1,364	1,393	1,706	1,484	1,449	1,457	1,602	1,651
Net Reserves % of Total Obligation	9.7%	8.7%	15.4%	15.4%	18.3%	16.2%	15.7%	15.4%	15.7%	16.0%
Portfolio:	**Transmission – 1000MW DC**									
Portfolio Resource Additions	790	834	1,370	1,273	1,319	1,951	2,012	2,275	3,197	3,552
Net Reserves (MW)	849	782	1,414	1,048	776	1,129	1,094	1,102	1,132	1,051
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	11.6%	8.3%	12.3%	11.8%	11.6%	11.1%	10.2%

Table F.1 Load Resource Capacity Report (Continued)

Portfolio:	**Transmission - 2000MW DC**									
Portfolio Resource Additions	790	834	1,370	1,273	1,319	1,951	2,012	2,275	3,197	3,552
Net Reserves (MW)	849	782	1,414	1,048	776	1,129	1,094	1,102	1,132	1,051
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	11.6%	8.3%	12.3%	11.8%	11.6%	11.1%	10.2%
Portfolio:	**Transmission - Asset Build Market**									
Portfolio Resource Additions	790	834	1,370	1,693	1,739	2,276	2,337	2,600	3,502	4,057
Net Reserves (MW)	849	782	1,414	1,468	1,196	1,454	1,419	1,427	1,437	1,556
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	16.3%	12.8%	15.9%	15.3%	15.1%	14.1%	15.1%
Portfolio:	**Coal/Gas III**									
Portfolio Resource Additions	790	834	1,370	1,498	1,894	2,461	2,522	2,785	3,657	4,212
Net Reserves (MW)	849	782	1,414	1,273	1,351	1,639	1,604	1,612	1,592	1,711
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	14.1%	14.5%	17.9%	17.3%	17.0%	15.6%	16.6%
Portfolio:	**Coal/Gas III - 10%**									
Portfolio Resource Additions	790	834	940	1,068	1,464	2,031	2,092	2,355	3,227	3,682
Net Reserves (MW)	849	782	984	843	921	1,209	1,174	1,182	1,162	1,181
Net Reserves % of Total Obligation	9.7%	8.7%	11.1%	9.3%	9.9%	13.2%	12.7%	12.5%	11.4%	11.4%
Portfolio:	**All Gas II**									
Portfolio Resource Additions	790	834	1,370	1,723	1,769	2,306	2,367	2,630	3,602	4,157
Net Reserves (MW)	849	782	1,414	1,498	1,226	1,484	1,449	1,457	1,537	1,656
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	16.6%	13.1%	16.2%	15.7%	15.4%	15.1%	16.0%
Portfolio:	**All Gas II - 10%**									
Portfolio Resource Additions	790	834	940	1,293	1,339	1,876	1,937	2,200	3,172	3,627
Net Reserves (MW)	849	782	984	1,068	796	1,054	1,019	1,027	1,107	1,126
Net Reserves % of Total Obligation	9.7%	8.7%	11.1%	11.8%	8.5%	11.5%	11.0%	10.8%	10.9%	10.9%
Portfolio:	**PacifiCorp Build II**									
Portfolio Resource Additions	790	834	1,370	1,783	1,829	2,366	2,427	2,745	3,382	4,167
Net Reserves (MW)	849	782	1,414	1,558	1,286	1,544	1,509	1,572	1,317	1,666
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	17.3%	13.8%	16.9%	16.3%	16.6%	12.9%	16.1%
Portfolio:	**PacifiCorp Build II - 10%**									
Portfolio Resource Additions	790	834	940	1,043	1,599	1,856	1,917	2,235	3,072	3,837
Net Reserves (MW)	849	782	984	818	1,056	1,034	999	1,062	1,007	1,336
Net Reserves % of Total Obligation	9.7%	8.7%	11.1%	9.1%	11.3%	11.3%	10.8%	11.2%	9.9%	12.9%
Portfolio:	**Diversified I**									
Portfolio Resource Additions	790	834	1,358	1,492	1,906	2,429	2,493	2,757	3,630	4,180
Net Reserves (MW)	849	782	1,402	1,267	1,363	1,607	1,575	1,584	1,565	1,679
Net Reserves % of Total Obligation	9.7%	8.7%	15.8%	14.0%	14.6%	17.6%	17.0%	16.7%	15.4%	16.3%

Table F.1 Load Resource Capacity Report (Continued)

Portfolio:	Diversified II									
Portfolio Resource Additions	790	834	1,358	1,747	1,811	2,334	2,398	2,717	3,655	4,135
Net Reserves (MW)	849	782	1,402	1,522	1,268	1,512	1,480	1,544	1,590	1,634
Net Reserves % of Total Obligation	9.7%	8.7%	15.8%	16.9%	13.6%	16.5%	16.0%	16.3%	15.6%	15.8%
Portfolio:	Diversified III									
Portfolio Resource Additions	790	834	1,358	1,717	1,781	2,274	2,338	2,402	3,570	4,120
Net Reserves (MW)	849	782	1,402	1,492	1,238	1,452	1,420	1,229	1,505	1,619
Net Reserves % of Total Obligation	9.7%	8.7%	15.8%	16.5%	13.3%	15.9%	15.3%	13.0%	14.8%	15.7%
Portfolio:	Alternative Technology II									
Portfolio Resource Additions	792	844	1,398	1,876	2,012	2,219	2,340	2,738	3,655	4,045
Net Reserves (MW)	851	792	1,442	1,651	1,469	1,397	1,422	1,565	1,590	1,544
Net Reserves % of Total Obligation	9.7%	8.9%	16.3%	18.3%	15.7%	15.3%	15.4%	16.5%	15.6%	15.0%
Portfolio:	Diversified IV									
Portfolio Resource Additions	790	834	1,358	1,492	1,841	2,334	2,398	2,662	3,535	4,085
Net Reserves (MW)	849	782	1,402	1,267	1,298	1,512	1,480	1,489	1,470	1,584
Net Reserves % of Total Obligation	9.7%	8.7%	15.8%	14.0%	13.9%	16.5%	16.0%	15.7%	14.4%	15.4%
Portfolio:	Renewable									
Portfolio Resource Additions	790	834	1,370	1,823	1,869	2,521	2,582	2,945	3,802	4,057
Net Reserves (MW)	849	782	1,414	1,598	1,326	1,699	1,664	1,772	1,737	1,556
Net Reserves % of Total Obligation	9.7%	8.7%	16.0%	17.7%	14.2%	18.6%	18.0%	18.7%	17.1%	15.1%

APPENDIX G – DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) provides an important component in PacifiCorp's commitment to becoming an increasingly sustainable utility business. DSM is defined as activities or programs that promote electric energy efficiency or conservation or more efficient management of electric energy loads. Essentially those efforts that reduce customer energy consumption and clip or shift loads from peak to off-peak hours through permanent equipment changes, short-term financial offers, education and awareness, behavioral changes, or utility dispatch (direct load control). PacifiCorp's definition of DSM includes programs that are also commonly called energy conservation, load management, load curtailment, demand-side resources, energy efficiency and demand response.

CLASSES OF DSM

The various types of DSM programs vary with their dispatchability, firmness of results, term of load reduction benefit and persistence over time. To clarify the conversation around DSM, these programs have been divided into four general categories:

Class 1 - Fully Dispatchable Resources

Load reduction only occurs while being actively controlled by the utility. Once customers agree to participate in a Class 1 DSM program, the timing and persistence of the load reduction is involuntary on their part. This type of DSM could affect business economic output.

Examples include residential and commercial central air conditioner load control, irrigation load control, electric water heater load control and interruptible tariffs (facilitated by an underfrequency relay or other utility control system).

Class 2 - Non Dispatchable: Growth Neutral

Energy and/or capacity savings that have been achieved through a technological change in appliances, equipment and/or structures. Savings will endure for the life of the installed system. This type of DSM does not negatively affect business economic output.

Examples include programs that incent customers to replace existing (or upgrade in new construction) customer-owned equipment to more efficient lighting, motors, air conditioning systems, etc. Program examples include PacifiCorp's Energy FinAnswer and the Compact Fluorescent Giveaway.

Class 3 - Non Dispatchable: Buydown

Short duration (hour by hour) energy and/or capacity savings that are achieved through actions taken by customers voluntarily, based on a financial incentive provided by PacifiCorp with hour-by-hour load reduction results measured on an individual customer basis. This type of DSM could negatively affect business economic output. Load reduction endures only for the duration, in hours, of the incentive offering. Permanent facility/equipment changes or improvements are not made. There is no persistence in the load reductions. Examples include Energy Exchange and curtailable tariffs.

Class 4 - Non-Dispatchable; Conservation Education

Energy and/or capacity reductions achieved through behavioral changes. Specific program results cannot be relied upon for planning purposes. Long-term, persistent changes will be seen in historical load growth pattern changes over time. Examples include Power Forward, Customer Energy Challenge, public education and awareness programs that promote energy-reducing methods such as conservative thermostat settings, turning off appliances when not in use, and inverted block and time-of-use pricing structures.

MODELING DSM

Because of the varying characteristics of the different classes of DSM, each are treated differently when modeled for the IRP.

Class 1 programs are dispatchable and are therefore modeled in a similar fashion to a peaking plant.

Class 2 DSM is being modeled as decrements (reductions) to the load forecast. Running the IRP model with and without these DSM decrements results in a difference in the present value of revenue requirements (PVRR) for that IRP Portfolio. This difference is the decrement value of obtaining the DSM decrement. If the cost of running the DSM programs in a particular decrement is less than the decrement value, then they are cost effective to the PacifiCorp system. The decrements to load do not need to be adjusted for transmission and distribution line losses since the load decrement is assumed on the load side of the utility meter. The decrement will also reduce the requirement for reserves and would reduce the modeled emissions costs of any fossil fuel generation that is displaced.

Class 3 DSM is modeled much as the Class 1 DSM is modeled because it is a short-term reduction in peak, however, because the customer controls the load reduction and can decide to ride through the curtailment by paying an economic penalty, this Class of load reduction is less reliable and therefore has less planning value than Class 1 DSM.

An appropriate amount of Class 4 DSM (education) will be included to support implementation of Class 1-3 programs, as well as enhance customer knowledge of the efficient use of electricity. The effects of Class 4 efforts will be seen in the historical load growth and load shape changes over time.

Class 1 DSM – Direct Load Control

The proposed program is the direct load control of central electric air conditioners of residential and small commercial customers. The location is the Wasatch Front in Utah where the growth of central electric air conditioners (CAC) in new construction and the conversion of swamp (evaporative) coolers to CAC is causing the peak demand to grow much faster than the general growth in energy usage.

Because PacifiCorp has limited experience with direct load control, the proposed program would be contracted out to an experienced, national firm on a pay-for-performance basis. PacifiCorp will only pay for proven demand reduction. PacifiCorp projects participation from more than 100,000 customers within 3 years. This would result in a maximum load reduction capability of 91 MW on the load side of customer meter. This is roughly equivalent to 100 MW at the generator level (adjusting for line losses).

The costs would consist of capacity payments and energy payments (for curtailment hours). This Class 1 DSM is put in all Portfolio model runs and will dispatch when costs are below generation alternatives.

Because of SB1149 in Oregon that created the Energy Trust of Oregon (ETO), PacifiCorp will be transferring management of the current utility programs to that organization. The public purpose charge to customers will fund existing and new DSM programs in Oregon for PacifiCorp's customers. The load forecast in the IRP contains the assumption that DSM in Oregon will be maintained at historical levels. As the ETO gets new programs designed and implemented, these new DSM "decrements" to the load forecast can be accommodated in future IRPs.

<u>Class 2 DSM – Conservation Measures</u>

There are a number of existing and proposed Class 2 DSM programs are under consideration. PacifiCorp is using the decrement to the load forecast approach to determine their value. Guidance for this decrement approach came from Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities by the Tellus Institute, September 1995. It would be ideal to run each program as its own decrement to the load forecast to determine a value for each program. However, individual programs are too small in scope to delay the construction of a needed supply-side resource. Therefore, large decrements are made in order to capture the benefits in delaying capital expenditures needed for new supply-side resources.

First, PacifiCorp in partnership with some external stakeholders, analyzed the current and proposed programs and determined a levelized cost per MWh for each program and ranked them into a resource stack of DSM programs. Figure G.1 shows a schematic of what this DSM resource stack may look like.

Figure G.1 Class 2 DSM Program Resource Stack (1)
Each letter represents a DSM program in a state. The X-axis represents the cumulative MWa of the programs. The Y-axis represents the levelized $/MWh of each program.

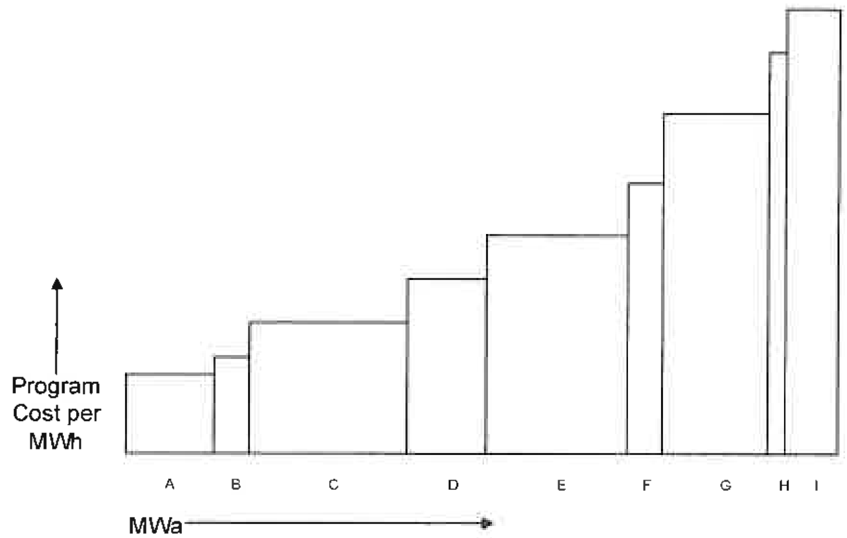


Figure G.2 Class 2 DSM Program Resource Stack (2)
A cost per MWh was chosen to divide the programs into two decrement blocks.

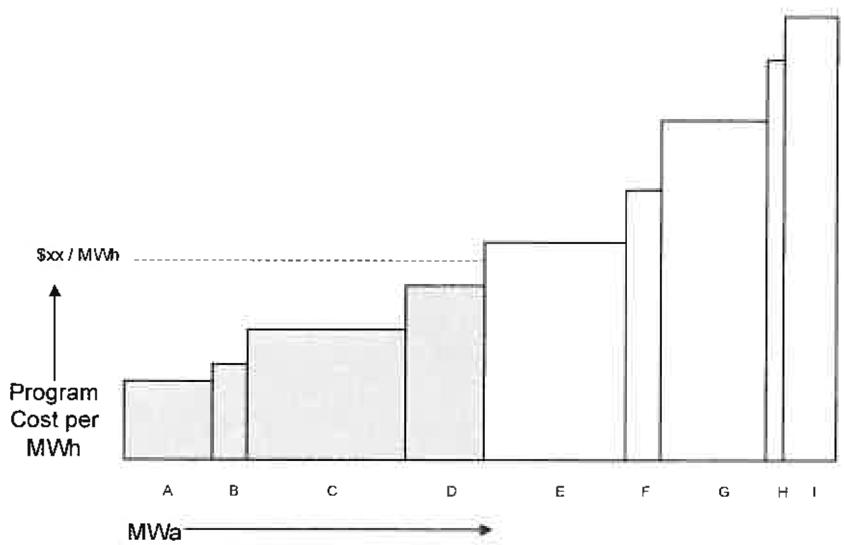
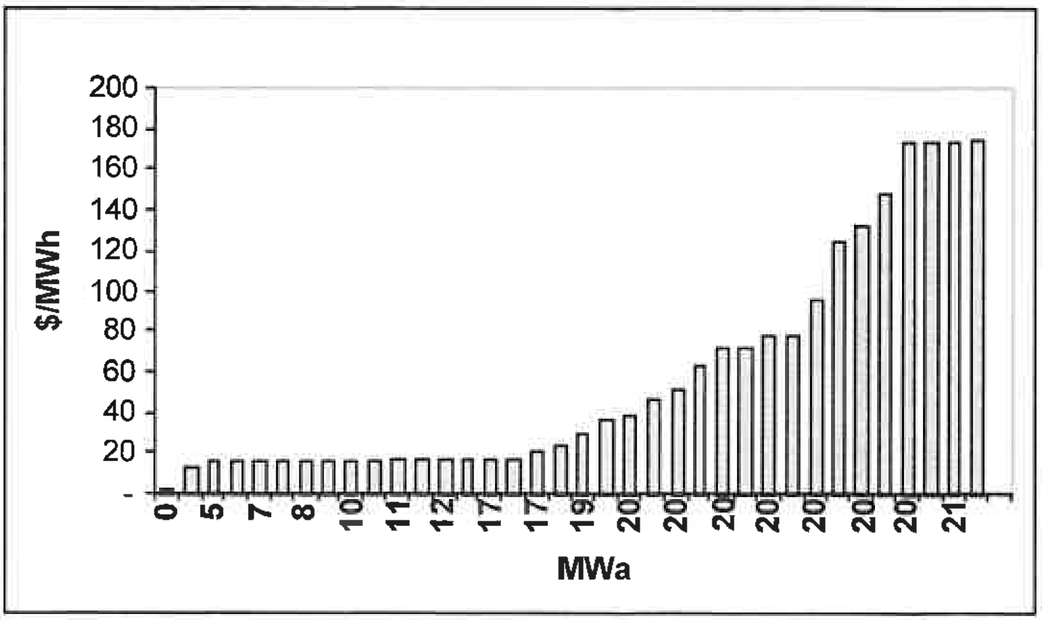


Figure G.3 shows the actual resource stack for the identified current and proposed DSM programs; program data listed in Table G.1. Each bar on the graph represents a DSM program in one state. The height of each bar represents the evaluated levelized cost per MWh of the DSM program.

Figure G.3 Class 2 DSM Levelized Costs - Actual DSM Program Resource Stack



Those programs analyzed with levelized costs below $39/MWh have been included as a decrement to load for all IRP portfolio model runs. These MWa figures represent the load reduction on the customer side of the meter. These figures would need to be grossed up for line losses (which vary for each customer class) to get the equivalent reduction at the generator level. The effect of accounting for line losses would reduce the $39/MWh figure to about $36/MWh. This figure compares favorable to supply-side generation costs. This resource accumulates to more than 150 MWa on the load side of the meter by 2013, equating to more than 165 MWa at the generator. Each program has been given an hourly annual energy savings load shape for each state for the duration of the energy savings measure. Therefore, the two decrements designed above have a 20-year hourly shape.

Table G.1 DSM Resource Stack

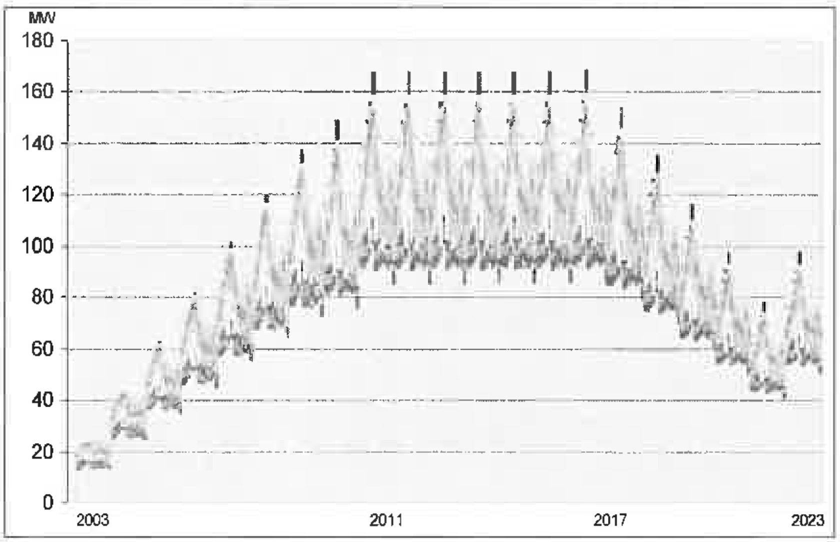
In order of ascending levelized costs per MWh.

State	Program [1]	First Year Cost	First Year Savings (MWh)	Life (y)	MWa	Cumulative MWa	Levelized Cost ($/MWh)	$/MWa
UT	CPN	250,000	3770	7	0.43	0.43	11.62	$ 580,902
WA	CFL	50,000	631	7	0.07	0.50	13.89	$ 694,136
WY	CFL	1,200,000	12,610	7	1.44	1.94	16.68	$ 833,624
UT	115	1,125,000	6,570	15	0.75	2.69	16.93	$ 1,500,000
WA	116	600,000	3,504	15	0.40	3.09	16.93	$ 1,500,000
WY	115	495,000	2,891	15	0.33	3.42	16.93	$ 1,500,000
WY	116	495,000	2,891	15	0.33	3.75	16.93	$ 1,500,000
ID	115	240000	1401.6	15	0.16	3.91	16.93	$ 1,500,000
ID	116	240000	1401.6	15	0.16	4.07	16.93	$ 1,500,000
UT	116	3,000,000	17,520	15	2.00	6.07	16.93	$ 1,500,000
WA	115	390,000	2,278	15	0.26	6.33	16.93	$ 1,500,000
ID	CFL	550,000	5,590	7	0.64	6.97	17.24	$ 861,896
ID	125	288,000	1,577	15	0.18	7.15	18.06	$ 1,600,000
CA	116	400,000	2,190	15	0.25	7.40	18.06	$ 1,600,000
WA	125	1,600,000	8,760	15	1.00	8.40	18.06	$ 1,600,000
UT	125	6,800,000	37,230	15	4.25	12.65	18.06	$ 1,600,000
WY	125	544,000	2,978	15	0.34	12.99	18.06	$ 1,600,000
CA	CFL	450,000	4,160	7	0.47	13.46	18.96	$ 947,596
UT	CFL	3,100,000	27,528	7	3.14	16.61	19.74	$ 986,486
WA	WEB	300,000	1,800	10	0.21	16.81	21.99	$ 1,460,000
UT	CAC	3,958,642	17,643	15	2.01	18.83	22.19	$ 1,965,522
ID	WEB	50,000	240	10	0.03	18.85	27.49	$ 1,825,000
ID	CAC	277,000	988	15	0.11	18.97	27.73	$ 2,455,992
WA	CAC	672,969	2,399	15	0.27	19.24	27.74	$ 2,457,361
UT	FRIG	2,247,000	15,166	6	1.73	20.97	29.56	$ 1,297,885
CA	WEB	50,000	200	10	0.02	21.00	32.99	$ 2,190,000
WA	FRIG	382,000	2,062	6	0.24	21.23	36.96	$ 1,622,852
WY	FRIG	548,640	2,791	6	0.32	21.55	39.21	$ 1,721,994
ID	FRIG	342,400	1309	6	0.15	21.70	52.18	$ 2,291,386
UT	HVAC	770,000	1,380	15	0.16	21.86	55.18	$ 4,887,826
WA	LIWX	800,000	1,000	20	0.11	21.97	66.33	$ 7,008,000
UT	RCX	266,000	495	5	0.06	22.03	125.46	$ 4,707,394
ID	LIWX	50,000	32	20	0.00	22.03	129.56	$13,687,500
CA	LIWX	100,000	60	20	0.01	22.04	138.20	$14,600,000
UT	ESP	654,000	357	15	0.04	22.08	181.18	$16,047,731
WY	ESP	98,100	54	15	0.01	22.08	181.18	$16,047,731

[1] CPN-Coupon for CFL, CFL – Compact fluorescent giveaway, 115 - Small Retrofit, 116 – Large Retrofit, 125 – FinAnswer, WEB – Web Audit, CAC – High Efficiency CAC, FRIG – Appliance Recycling, HVAC – AC Best Practices Service, LIWX – Low Income Weatherization, RCX – Retro Commissioning, ESP – Energy Star Appliance

Figure G.4 shows the approximate load shape of this first DSM decrement over the 20 year IRP planning horizon.

Figure G.4 DSM Class 2 Hourly Load Decrement



Once the final one or two finalist IRP portfolios were identified, the second DSM decrement portfolio model run was completed (identified programs with levelized costs greater than $39/MWh).

Additional Planning Decrements
To determine the decrement values specific to the PacifiCorp system for further Class 2 DSM resources, two additional "planning" decrements of 150 MW and 300 MW beginning in FY 2008 were run. The 150 MW decrement was shaped with load factors of 1%, 10% and 40%. The 300 MW decrement was shaped with load factors of 1%, 20% and 60%. These six additional model runs give us the decrement values for these six different load decrements to the final IRP Portfolio. With this information, PacifiCorp will be able to seek appropriate additional DSM programs that match the indicated load shape within the decrement values identified.

Class 3 DSM - Curtailment
Proposed interruptible and curtailable tariffs are being designed to offer to customers with loads greater than 1 MW and a load reduction commitment of at least 200 kW. The target market for these tariffs will come from Energy Exchange participants. With the Energy Exchange, customers could not predict any income from their ability to curtail load when needed on the PacifiCorp system. With these proposed tariffs, customers would commit to a load reduction level and receive a capacity payment for this curtailment "option" PacifiCorp would have. The customer would also receive an energy payment for actual curtailment hours. A penalty would be invoked for customers who do not curtail as contracted.

This Class of DSM is modeled in a similar fashion as Class 1, much like a peaking unit, however, because the customer has ultimate control of the curtailment, and could "buy through" by paying the penalty, it has less planning value as a resource to PacifiCorp.

<u>DSM Summary</u>

Table G.2 provides a summary of the DSM by Class.

Table G.2 DSM Summary

		MW at Load	MW at Generator
Class 1	CEC Load Control	91 MW peak	100 MW peak
	Irrigation Load Control	50 MW peak	56 MW peak
Class 2	Installed Measures	150 MWa	160 MWa
	Planning Decrements	150-300 MWa	160-320 MWa
Class 3	Curtailment	50 MW peak	52 MW peak
Potential Total		**150-450 MWa**	**160-480 MWa**
		191 peak MW	**208 peak MW**

Table G.3 shows the latest projection from the Energy Trust of Oregon. It shows their expected contribution to the PacifiCorp service territory Class 2 DSM accomplishments.

Table G.3 Energy Trust of Oregon Projected DSM Achievements (MWa)

2004	2005	2006	2007	2008	2009	2010	2011	2012
10.7	11.2	11.8	12.0	12.2	12.6	12.8	13.1	13.4

DECREMENT PROCEDURE TO DETERMINE DSM DECREMENT VALUES

Some low cost Class 2 DSM programs were inserted in all IRP portfolios based on a low levelized cost per MWh that is comparable to new generation resource options. All programs with evaluated costs less than $39/MWh at the load were included in this decrement to the load forecast. This allows for a base of DSM in all IRP portfolios.

Additional DSM decrements are made with hourly modeling of identified DSM program opportunities. Planning decrements are created with hourly load shapes based on identified end-use characteristics to mimic the potential load shape of new DSM programs based on those or similar end-uses.

Through the IRP modeling process, the preferred generation portfolio is selected balancing new generation and associated transmission costs (NPVRR) with an assessment of the financial and operating risks. The additional planning decrement study is performed using this most likely portfolio of mix of resources, yielding an improved assessment of DSM value.

New model runs are then made on the chosen additional load decrements (MWa) and selected load factors. Table G.4 illustrates the combinations of load and load factors to represent a large range of potential DSM opportunities selected by PacifiCorp for this IRP:

Table G.4 DSM Load Decrement Summary

Decrement Name	Decrement Description	Peak	Load Factor	End-Use
D-P40	Identified programs <$39/MWh			Combination of all programs in decrement
D-P40+	Identified programs >$39/MWh			Combination of all programs in decrement
D150-1	150 MW	150 MW	1%	Direct load control – 100 hours/yr at peak
D150-10	150 MW	150 MW	10%	Residential air conditioning
D150-40	150 MWa	375 MW	40%	Commercial lighting
D300-1	300 MW	300 MW	1%	Direct load control
D300-20	300 MW	300 MW	20%	Commercial air conditioning
D300-60	300 MWa	500 MW	60%	Near the system load factor

D-P40 was reduced from the load forecast for all portfolios beginning the first year of the study, FY 2004. The other decrements were implemented as of April 2008 (fiscal 2009) with the assumption that programs will take several years to build to the volumes in this study. The purpose is only to value them at their full impact, when they will be most likely to impact resource planning decisions.

<u>Decrement Procedure</u>

1. Each decrement will result in a new Portfolio run.
2. An hourly representative program shape will be created for each decrement with the following characteristics. All decrements include an additional 8.5% reduction to account for average distribution line losses included in the load forecast.
   - D-P40+: The hourly shape of this combination of programs was created by Quantec based on program design information supplied to them by PacifiCorp. The decrements for each program were combined by State, resulting in five hourly total program shapes, extending over the 20-year life of the study. Subtracting the program shapes from the base load shapes creates five new load shapes. One for each load center.
   - D150-1 A 150 MW load reduction is made to the Utah Main load center for 4-6 hours per day during the super peak of 16 days per year. This pattern represents a dispatchable A/C load control program. Customers will not be subject to AC control for more than six hours at a time. The load shape used for modeling

this program was created by first ranking the hourly loads for July and August and then selecting the top 88 hours. For each of the selected hours, 150 * 1.085 (assuming 8.5% distribution load losses included in load forecast) was subtracted from the Utah Main load file. Some manual adjustment was necessary to ensure that a maximum of 6 continuous hours was selected. This hourly program pattern is then repeated for each of the 20 years of the study, assuming the load forecast follows a similar hourly pattern each year.

- D150-10 A 150 MW peak load reduction is made, prorated to load centers by share of total system retail load and given an hourly shape matching residential air conditioning supplied by Quantec with a load factor of 10%.
- D150-40 A 150 MWa load reduction is made (375 MW peak), prorated to load centers by share of total system retail load, and given an hourly shape matching commercial air conditioning supplied by Quantec with a load factor of 40%.
- D300-1 Same as D150-1 except a larger load reduction. A 300 MW load reduction is made to the Utah Main load center for a maximum of 6 hours per day during the super peak on 16 days per year.
- D300-20 A 300 MW peak load reduction is made, prorated to load centers by share of total system retail load and given an hourly shape with a 20% load factor, matching commercial lighting supplied by Quantec.
- D300-60 A 300 MWa load reduction is made (500 MW peak), prorated to load centers by share of total system retail load, and given an hourly shape matching the load center load shape which approximately has a 60% load factor

3. Each of the seven decrement program load shapes above represent a unique adjustment to the load forecast. Each shape is then split among five load centers in the model based on the ratio of area load to total load and is subtracted from the existing load shape to create a new hourly load forecast. The exceptions to this shape split are the 1% load factors, which are only applied to the Utah load shape. Oregon is not included in the total system load calculation since future DSM programs will be developed by the ETO. Table G.5 gives details of the distribution by load center.

Table G.5 DSM Program Distribution by Load Center

Program Distribution by Load Center	
Idaho	4.7%
Utah	58.4%
Mid Columbia	9.4%
West Main	10.2%
Wyoming	17.3%
TOTAL	100%

4. Since these decrements can have a substantial impact on annual peak load, which is the basis for resource capacity planning, a revised load/resource balance must be produced for all decrement runs except for DP40+. The 40+ programs are not of great enough magnitude or frequency to displace or shift the timing of new generation and therefore do not require an adjusted resource portfolio. Although D150-1 and D300-1 are dispatched for only 1% of all peak hours in the year, it's assumed that installation of an East peaker could still be delayed

since in our load forecast, the peak obligation declines when 150 – 300 MWs is removed for just 1% of hours. In 2004 modeling results, Gadsby and West Valley GTs run with a 2-5% capacity factor.

5. For those decrements with revised L/R balances and new peak annual demands, the Diversified I resource mix will be adjusted to more closely meet the gap of the new load shapes. This step will create 4 new portfolios using the same methodology as the main IRP portfolio development process.
6. Run the PROSYM model for all seven new load shapes with either the base Diversified I portfolio mix or the new resource portfolios to get a revised PVRR, depending on Steps 4 and 5.
7. Develop a Decrement Scorecard highlighting the differences in PVRR and other relevant value measures.

The difference in PVRR of the various decrement runs is the net present value of decrement values of implementing DSM programs that match the indicated hourly load reduction for each decrement. These become DSM targets to find programs that can fill them within the decrement values calculated by the model.

The decrement values consist of the modeled value of displaced fuel. pollutants not emitted and capital investment (generation and associated transmission) delayed or eliminated.

Results

Portfolio Assignment

All DSM decrement runs were compared to the performance of the Diversified I portfolio which contains the resources outlined in Table G.5 below. D-P40 is the equivalent of this portfolio. D-P40+, also contains the same resource mix but the individual program shapes reduce the load files accordingly (i.e., they don't allow deferral of new generation additions, but they do reduce operation of peak generation.) The average planning margin for years 2009 to 2013 for this resource mix is 16%.

Table G.6 Base Resources

Portfolio	Diversified Gas/Coal I –D-P40+, D150-1, D300-1	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MWs
East	Thermal Contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control – peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (installed capacity in MW)				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
	Peakers (Mona, SCCT Frame)										200	200

	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
												3374
West	Thermal contract (installed capacity in MW)			25	25	25		25	25	25	25	175
	Class 1 DSM (load control – peak MW capability)											0
	Class 2 DSM (MWa added each year)	5	2	2	2	2	2	2	2	2	0	22
	Wind (installed capacity in MW)			100		200		200		200		700
	Flat Contract (7X24)								200			200
	3-Year Flat Off-Peak	500			-500							0
	Peaking Contract									100		100
	CCCT (Albany)				570							570
	West Market (Short Term)	500										500
	Reserve Peakers (West)			230						230		460
												2227

New Portfolio Design

New portfolios were designed for the remaining four decrements using the process outlined in Chapter 4. Since the programs are mostly located in Utah, Idaho, and Wyoming due to weighting to load percentage, only East side resources were impacted for these portfolios. The West Side of the portfolio remains unchanged from the Diversified Portfolio I mix. In the East, the new load shape affected the planning process in different ways, making it difficult to methodically remove, reduce or move resources and retain the identical planning margin each year. Only three resource types were adjusted in each of the new portfolios, either the Gadsby Repower CCCT at, Mona peakers, or Reserve Peakers East. By adjusting only similar resources in each portfolio, the results are thought to be more comparable. For example, if one portfolio removed Hunter 4 and another removed the CCCT; it would be very difficult to draw relative system PVRR impacts driven by the load adjustment. This study is created to show how these varying load reductions can impact the resources PacifiCorp chooses and what the cost tradeoffs are for achieving these resource changes.

D150-10

This shape reduced annual peak load by 150MW in the summer months and increased the length of PacifiCorp's position report in the East. By 2009, there is the potential to reduce the Gadsby Repower CCCT 2X1 5100 MW with duct firing to a 1x1 of 255MW and maintain an average of 15.5% planning margin for 2009-2013. Table G.7 shows the revised portfolio make-up.

Table G.7 D150-10 East Resources

Portfolio	D150 – 10	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MWs
East	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 1 DSM (load control – peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added	30	12	11	12	12	12	12	12	12	0	123

Portfolio		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MWs
	each year)											
	Wind (installed capacity in MW)				200		200		200		120	720
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)					575						575
	CCCT (Mona)									480		480
X	**CCCT (Gadsby Repower)**						255					255
	Peakers (Mona, SCCT Frame)										200	200
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
												3119

D300-20

This shape reduced annual peak load by 300MW in the summer months and greatly increased the length of PacifiCorp's net position in the East. The Gadsby Repower CCCT of 510MW can be eliminated from the near term planning horizon as long as the two Mona SCCT frame peakers, each 100MWs, are moved forward one year to 2012. This mix results in a 2009-2013 average planning margin of 15.2%. Table G.8 shows the revised portfolio make-up.

Table G.8 D300-20 East Resources

Portfolio	D300 – 20	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MWs
East	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 1 DSM (load control – peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (installed capacity in MW)				200		200		200		120	720
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)					575						575
	CCCT (Mona)									480		480
X	**CCCT (Gadsby Repower)**											**0**
X	**Peakers (Mona, SCCT Frame)**									**200**		**200**
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
												2864

D150-40

This shape reduced annual peak load by 375MW in the summer months.. The Gadsby Repower 2x1 CCCT of 5100MW was removed and the two Mona SCCT frame peakers each 100MWs, were moved ahead to 100MWs in 2010 and 200 in 2012. The 2009-2013 average planning margin is 16%. Table G.9 shows the revised portfolio make-up.

Table G.9 D150-40 East Resources

Portfolio	D150 – 40	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MWs
East	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 1 DSM (load control – peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (installed capacity in MW)				200		200		200		120	720
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)					575						575
	CCCT (Mona)									480		480
X	**CCCT (Gadsby Repower)**											**0**
X	**Peakers (Mona, SCCT Frame)**							**100**		**200**		**300**
	East Market (Short Term)	500										500
	Reserve Peakers (East)			200							300	500
												2964

D300-60

This shape reduced annual peak load by 500MW and had a large impact on the resource portfolio. The Gadsby CCCT as well as the 200MW of Mona peakers were removed from the portfolio without reducing the planning margin which averages higher than the other portfolios at 16.1%. East reserve peakers could also be delayed to 100 MW in 2008 and 300MW in 2013. Table G.10 shows the revised portfolio make-up.

Table G.10 D300-60 East Resources

Portfolio	D300 – 60	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total MWs
East	Thermal contract (installed capacity in MW)	0	0	25	25	25	0	25	25	25	25	175
	Class 1 DSM (load control – peak MW capability)	30	30	31								91
	Class 2 DSM (MWa added each year)	30	12	11	12	12	12	12	12	12	0	123
	Wind (installed capacity in MW)				200		200		200		120	720
	Super Peak Contract	225			-225							0
	Coal Base Load (Hunter 4)					575						575
	CCCT (Mona)									480		480
X	**CCCT (Gadsby Repower)**											**0**
X	**Peakers (Mona, SCCT Frame)**											**0**
	East Market (Short Term)	500										500
X	**Reserve Peakers (East)**			2		**100**					300	**400**
												2564

D150-1, D300-1

These shapes reduced annual peak load by 150 and 300MW for 1% of the top demand hours in each year. One 100MW East reserve peaker was removed from 2006 for each of these model runs.

Decrement Case Comparison

Table G.11 shows the nominal results of these decrement cases for each year of the planning period. The 1% load factor cases only show the nominal dollar value of that type of DSM program option. Comparing costs per MWh are not meaningful because of the extremely low load factor resulting in extremely low energy. One percent decrements have a capacity deferral objective rather than an energy and capacity deferral. The higher load factor cases have significant capacity and energy benefits and are displayed with their nominal values per MWh of decrement.

Transmission and Distribution Deferral Benefits

The decrement values in Table G.11 do not include the time value of deferred transmission or distribution costs that result from demand growth . Specific evaluation of these benefits are not included in this IRP. These types of benefits are geographically specific, based on the local T&D system growth rate and the local, concentrated effects of DSM programs. PacifiCorp is not applying a general, systemwide transmission and distribution savings. Specific investment needs must be indentified for deferral just as this IRP identified specific generation investment that the DSM decrements could defer if implemented. As specific programs are designed, local T&D benefits will be considered if they can result is the deferral of identified transmission and distribution investment.

Table G.11 Decrement Case Values

Decrements begin in fiscal 2009

Decrement Case		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
D150-1	Nominal Decrement Value[1]						9,887	9,605	7,607	8,853	9,951
D300-1	Nominal Decrement Value[1]						10,197	9,663	8,415	9,777	11,007
D150-10	Nominal Decrement Value[1]						24,307	20,704	22,173	23,257	23,643
	Delta in GWh[2]						104	110	117	128	141
	Delta in nominal $/MWh[3]						234	188	189	181	168
D300-20	Nominal Decrement Value[1]						58,588	55,383	54,749	38,039	58,376
	Delta in GWh[2]						628	609	641	670	671
	Delta in nominal $/MWh[3]						93	91	85	57	87
D150-40	Nominal Decrement Value[1]						78,318	68,896	68,881	52,678	75,510
	Delta in GWh[2]						1,298	1,274	1,291	1,291	1,312
	Delta in nominal $/MWh[3]						60	54	53	41	58
D300-60	Nominal Decrement Value[1]						134,434	127,113	131,334	136,268	162,352
	Delta in GWh[2]						2,688	2,654	2,665	2,652	2,628
	Delta in nominal $/MWh[3]						50	48	49	51	62

Decrement Case		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
D150-1	Nominal Decrement Value[1]	10,037	8,802	10,121	10,035	8,387	11,737	7,658	3,241	8,019	15,893
D300-1	Nominal Decrement Value[1]	9,647	9,107	12,118	11,410	9,774	12,531	8,540	5,359	10,559	18,301
D150-10	Nominal Decrement Value[1]	19,420	20,596	17,949	18,588	14,405	13,391	11,949	5,683	13,729	9,892
	Delta in GWh[2]	141	141	141	141	141	141	142	142	141	140
	Delta in nominal $/MWh[3]	138	146	127	132	102	95	84	40	97	70
D300-20	Nominal Decrement Value[1]	54,626	54,464	52,643	53,926	54,648	44,770	43,250	36,555	43,949	43,607
	Delta in GWh[2]]	673	673	674	672	672	672	673	671	673	702
	Delta in nominal $/MWh[3]	81	81	78	80	81	67	64	54	65	62
D150-40	Nominal Decrement Value[1]	72,233	75,640	74,855	74,824	76,126	72,282	69,756	65,403	70,033	68,441
	Delta in GWh[2]	1,316	1,316	1,320	1,312	1,316	1,316	1,320	1,312	1,317	1,375
	Delta in nominal $/MWh[3]	55	57	57	57	58	55	53	50	53	50
D300-60	Nominal Decrement Value[1]	160,329	166,841	168,971	174,487	176,111	171,616	176,394	171,531	185,479	193,295
	Delta in GWh[2]	2,629	2,628	2,636	2,628	2,628	2,628	2,635	2,629	2,629	2,786
	Delta in nominal $/MWh[3]	61	63	64	66	67	65	67	65	71	69

[1] Difference between the Revenue Requirement of Diversified Portfolio 1 with the base load forecast and the revneue requirement for the of Diversified Porfolio 1 with the planning decrement subtracted from the base load forecast in $million.

[2] Total MWh of the decrement.

[3] Nominal Decrement Value divided by Delta in MWh.

APPENDIX H – RISK ASSESSMENT METHODOLOGY

INTRODUCTION

This paper describes PacifiCorp's approach for assessing risk and uncertainty in its Integrated Resource Plan analysis. The paper focuses on the development of volatility and correlation parameters for important electricity market drivers.

BACKGROUND

Performing analysis of the cost of electricity supply under an assumption of expected conditions in the future provides important information for decision makers regarding how different supply portfolios perform. However, decision makers are also interested in performance of these portfolios under influences that vary from expected. Of particular note for PacifiCorp are the following uncertainties:

Load
Retail load (or firm load obligations) can vary significantly in the short term due primarily to temperature fluctuations in the PacifiCorp service territory. An examination of historical daily load provides insight into how these loads might vary from day to day in the future. Over the longer term, economic conditions and technological changes have a significant effect on load growth rates.

Natural Gas Price
Natural gas prices have exhibited significant volatility in recent years. An examination of historical daily natural gas prices provides insight into how these natural gas prices might vary from day to day in the future. Longer-term uncertainties relate to the supply and demand for natural gas as an energy stock.

Spot Market Power Prices
Spot market electricity prices affect portfolios through the dispatch of PacifiCorp generation assets. When spot prices are low, it may be economical to displace some of PacifiCorp's mid-merit generation. When spot prices are high, it may become economical to operate coal and natural gas resources at levels higher than needed to cover firm obligations, contributing revenues that reduce system electricity costs. An examination of historical daily spot market electricity prices provides insight into how these prices might vary from day to day in the future. Longer-term market price trends are uncertain due to general economic conditions and general supply and demand for generating resources. These longer-term trends can have a significant effect on the value of competing portfolios as well.

Hydrogeneration
Hydrogeneration makes up a significant portion of PacifiCorp's existing resource portfolio. History demonstrates that the amount of generation will vary from time to time as a result of

different precipitation levels. An examination of historical hydrogeneration data (both daily changes demonstrated by actual operation and longer-term changes reflected in hydrogeneration regulation models) provides insight into how hydrogeneration may vary in the future.

Generation Forced Outage

It is well understood that generation units are taken out of service from time to time as a result of unanticipated problems (forced outage), and the random nature of this aspect of generation must be accounted for in any portfolio analysis

While the operation of the PacifiCorp system in meeting its load is a traditional economic dispatch activity, any forecast of system operation must take into account the varying nature of these variables, as each of these drivers is directly related (and correlated) to the price and volatility of electricity. Differences in makeup of potential portfolios will therefore necessarily result in different expected outcomes depending on the nature of the volatility of these key parameters.

PacifiCorp's analysis of potential supply portfolios attempts to look at the possible future performance of each portfolio under uncertainty. Currently, PacifiCorp is performing its assessment of portfolios with Henwood's PROSYM and MarketSym products on both a deterministic and stochastic basis. Deterministic forecasts are based on the expected value of all input parameters, whereas stochastic assessments include specific volatility and correlations among parameters.

The analysis of uncertainty in outcomes is achieved through "Monte Carlo" (random or stochastic) selection of electricity system variables effecting the dispatch and operation of the PacifiCorp electricity system. The distributions and inter-relationships of the random variables are derived from the historical behavior of loads, natural gas prices, spot electricity prices, and hydrogeneration.

STOCHASTIC ANALYSIS MODEL AND ASSUMPTIONS

Stochastic Model

PacifiCorp's analysis is being performed with the following stochastic variables:

- Fuel prices (natural gas at MidC and two natural gas prices in Utah)
- Electricity market clearing prices (MidC, COB, Four Corners, and PV)
- Electric transmission area loads (PacifiCorp-West, Wyoming, and Utah regions) and
- Hydrogeneration basins (PacifiCorp West and PacifiCorp East).

The development of expected value and stochastic parameters for this analysis is discussed below.

Henwood's stochastic analysis uses the modeling capability of the MarketSym and PROSYM stochastic module. In this process an expected value trajectory for each price or physical variable and a set of stochastic model parameters are developed and entered by the user, using stochastic data input tools. During execution, Monte Carlo simulation is performed with daily random draws for average daily values for prices and loads and weekly random draws for hydrogeneration energy availability. Within each week, generation units are committed and dispatched as if they have perfect foresight of stochastic values for that week only.

Two-Factor Lognormal Mean-Reversion Model

The stochastic model used in PacifiCorp's analysis is a two-factor, lognormal mean-reversion model. One factor represents short-run variations that are mean reverting, and the other factor represents longer-term variations that follow a random walk. Mean reversion implies that after a price is initially disrupted (higher or lower), it will tend to revert back towards its expected value. The rate at which the random variable tends to revert to the expected value is an input to the process. Separate volatility and correlation parameters are used for modeling short-run price variations (e.g., uncertain weather or outages) and longer term price variations (e.g., uncertain fuel supply costs, load growth, or hydrogeneration year). Antithetic sampling is used to reduce sampling variance.

The stochastic two-factor lognormal mean reversion model:

1. Simulates a general stochastic process capable of representing fuel prices, electricity prices, electric loads, and hydrogeneration energy availability.
2. Uses an expected forecast as an equilibrium value for each time period.
3. Uses two distinct stochastic factors for each stochastic variable – for short-term and longer-term variations.
4. Assumes a lognormal distribution for each stochastic factor.
5. Allows contemporaneous correlation among all, some, or none of the input and output prices.
6. Allows use of seasonal and annual volatility and correlation parameters, with short-term reversion to mean, to handle cyclical patterns of energy commodities.

The specific discrete time representation of the model is:

$$S_{n,t} = S_{n,t-1} + L_{n,t} - L_{n,t-1} + \alpha_{n,t}(L_{n,t-1} - S_{n,t-1}) + \sigma^S_{n,t}\varepsilon^S_{n,t} - \mathrm{Var}[S_{n,t}]/2 \quad (1)$$

$$L_{n,t} = L_{n,t-1} + \delta_{n,t} - (\sigma^L_{n,t})^2/2 + \sigma^L_{n,t}\varepsilon^L_{n,t} \quad (2)$$

$$\mathrm{E}[\varepsilon^S_{n,t} \cdot \varepsilon^L_{n,t}] = \mathrm{Cov}^{S,L}_{n,t} = 0 \Rightarrow \rho^{S,L}_{n,t} = 0 \quad (3)$$ [19]

$$\mathrm{E}[\varepsilon^S_{m,t} \cdot \varepsilon^S_{n,t}] = \mathrm{Cov}^S_{m,n,t} \neq 0 \Rightarrow \rho^S_{m,n,t} \neq 0 \quad (4)$$

$$\mathrm{E}[\varepsilon^L_{m,t} \cdot \varepsilon^L_{n,t}] = \mathrm{Cov}^L_{m,n,t} \neq 0 \Rightarrow \rho^L_{m,n,t} \neq 0 \quad (5)$$

[19] Assuming zero correlation between the long and short-run stochastic changes is a simplifying assumption. However, this assumption represents movements in the stochastic variable that we would expect to observe in a real market situation. It is justified both by the unavailability of quantitative data from which to estimate a correlation, either positive or negative, between short-run shocks and long-run shocks and by the structure of the model in which short run shocks to the stochastic variable apply to deviations from the value of the long run distribution.

This assumption assures that positive (upward) short-run spikes in the value of the stochastic variable are statistically independent from positive (upward) trends in the long-run equilibrium value of the stochastic variable, and vice versa. Relaxing this assumption could lead to model (parameter) induced bias in the resulting value of the stochastic variable.

Where:
n = commodity (fuel price, electricity price, electric load or hydrogeneration)
t = time period of observation (e.g., day for prices and loads, or week for hydrogeneration)
S_n = logarithm of short-run or spot price for commodity n
L_n = logarithm of long-run or equilibrium price for commodity n
$\alpha_{n,t}$ = rate of mean-reversion in spot price for commodity n in period t
$\delta_{n,t}$ = expected rate of growth (drift) of equilibrium price for commodity n in period t
$\sigma^S_{n,t}$ = volatility of spot price returns for commodity n in period t
σ^L_n = volatility of equilibrium price growth rate for commodity n
ε^S = normally distributed random vector (mean = 0, s.d.= 1)
ε^L = normally distributed random vector (mean = 0, s.d.= 1)
$\rho^{S,L}$ = correlation of spot and long run price stochastic changes
$\rho^S_{m,n}$ = correlation of spot price stochastic changes for commodities m and n
$\rho^L_{m,n}$ = correlation of drift rate stochastic changes for commodities m and n
Var = variance.
$\mathrm{Cov}_{m,n}$ = variance-covariance matrix for stochastic changes in commodities m and n

For electricity prices daily values are used in the above model. Once the simulated average price is determined for each day, hourly spot prices for that day are scaled up or down in proportion to those for the expected daily price shape.

Note: The error vectors are independent and identically distributed (i.i.d); there is no autocorrelation within an error vector. This is the structure of the model used, and the parameters and coefficients are developed accordingly. Random shocks in successive periods are drawn independently, and short-term reversion to mean is accounted for.

The primary justification for this assumption is the need to limit the complexity of the model. If this assumption were relaxed (this would be equivalent to switching to an AR(2) or higher process), we would effectively be implementing a new model. Developing and utilizing data for autocorrelation of stochastic variables would add to the complexity of the analysis and simulation process. We have not studied the feasibility of such a modification to the analytic process, or what the effect, if any, would be on the results.

Stochastic Parameters: Short-Term

Estimates of short-term volatility and mean-reversion parameters were developed statistically using ordinary least squares (OLS) regression on historical data. For natural gas prices, market hub daily spot prices published by "Intelligence Press" were used. For electricity prices, market hub daily spot prices published by Power Market Weekly were used. Historical loads as reported to FERC were used for electricity loads. Columbia River basin data published by the University of Washington were used for hydrogeneration.

- Natural gas market prices at Sumas (1998-2002) were used for MidC gas volatility, and gas market prices at Opal (1993-2002) were used for both Utah gas price volatilities.
- On-Peak daily forward electricity market clearing prices were used for MidC, COB and PV (1996-2002) and for Four Corners (1997-2002).
- Historical loads aggregated for electric transmission area PAC-West, Wyoming and Utah were used.
- Weekly outflow data of the Dalles forebay on Grand Coulee dam was used for hydrogeneration energy availability for both West and East hydrogeneration basins.

For estimation of stochastic parameters, historical data was "cleaned" by capping gas prices at $20/MMBtu and eliminating electricity prices between June 2000 and May 2001. Volatility can vary from year to year, which is why multiple years of data were used. Four "hydrogeneration" seasons were defined: Summer (hold) July-October, Fall (draft) November-January, Winter (refill) February-March, and Spring (runoff) April-June. The regressions pooled the data for the same season across the years in the sample period.

The short-term correlation parameter values were calculated (as the linear correlation between the contemporaneous residuals of the regressions) for each season. Correlation values are used in the stochastic simulation to adjust the initial random draws for each variable, using Cholesky decomposition, in order to account for their correlation of unexpected movements.

Correlations between each pair of stochastic variables were calculated using the statistical estimation tool.

The statistical tool estimated the short-term volatility and mean-reversion parameters as follows.

Let p = ln(P), where P is the spot value. The continuous time (as $\Delta t \to 0$) short-term mean-reversion process is:

$$p_t - p_{t-1} = (1 - e^{-\alpha})(\overline{p} - p_{t-1}) + \varepsilon_t$$

or

$$p_t = (1 - e^{-\alpha})\overline{p} + e^{-\alpha} \cdot p_{t-1} + \varepsilon_t$$

For daily (weekly, or other discrete) time data, the above process was estimated with OLS regression as an autoregressive lag 1 period (or AR(1)) equation:

$$p_t = a + b \cdot p_{t-1} + \varepsilon_t$$

The mean-reversion rate is then calculated from the AR(1) regression parameter:

$$\hat{\alpha} = 1 - \hat{b}$$

and the short-term volatility rate (on a daily basis) is equal to the standard error of the regression:

$\hat{\sigma} = \hat{s}$ where s is the standard error of the regression.

The volatility rate, then, is the residual volatility, after accounting for the mean reversion tendency, rather than total volatility.

The regression intercept ($\hat{a}$) coefficient is not needed, since it is only used in the calculation of the average value:

$$\bar{p} = \frac{\hat{a}}{1-\hat{b}}$$

Stochastic Parameters: Long Term

Estimating longer-term volatility and the correlation of variables for electricity and natural gas prices are somewhat more subjective than estimating the short-term parameters for several reasons. First, wholesale market prices for electricity are not available for the twenty or more years that would be necessary to statistically estimate its long-run volatility. Regulation of natural gas wellhead and transmission rates in past years also make the available long-term prices for natural gas a more challenging subject for simulation.

For natural gas, an annual long-term volatility of 14.51% was adopted from econometric analysis by Pindyck (Energy Journal, 1998), based on data for the 1970-1996 period. This rate was scaled down to a daily rate by dividing by the square root of 365. Lacking long-term data for wholesale electricity prices, we assume the same annual long-term volatility of 14.51% for electricity. This assumption may be justified by noting that electricity is a manufactured commodity whose long-run price is largely determined by the cost of fuel. Through experimental calibration and judgment, a long-term drift correlation rate of 0.95 was assumed between each pair of gas and electric prices, gas and gas prices, and electric and electric prices. This near-unity value results in electricity and natural gas prices tending to move together over any particular Monte Carlo trajectory.

For loads, an annual volatility of 1.2% was adopted as an estimate of load growth uncertainty based on a comparison with assumed annual electric load growth.

For hydrogeneration availability, fifty years worth of available hydrogeneration based on the BPA 1999 "Whitebook" was analyzed. Average availability for each of the four hydrogeneration seasons defined above was calculated. Representation of stochastic variables is presently limited to the two factor lognormal model defined previously. Hydrogeneration is modeled by using the long-term variable to represent the shape of seasonal generation. Long-term volatility is set to zero so that uncertainty in hydrogeneration does not grow over the study time horizon. Annual volatility in hydrogeneration is captured by reducing the mean reversion rate to a level that reasonably represents the year-to-year variability of water conditions.

Short-Term Volatility Parameters

The tables below present the volatility parameters that are currently being used for the PacifiCorp stochastic assessments that were developed using the Simple Lognormal AR(1) Mean Reverting Model.[20]

PAC-West Load

Season		Alpha	Sigma
F	1	0.0970	0.0132
W	2	0.0410	0.0080
Sp	4	0.0400	0.0080
Sum	7	0.0310	0.0080
F	11	0.0970	0.0132

Utah Load

Season		Alpha	Sigma
F	1	0.0420	0.0133
W	2	0.0120	0.0080
Sp	4	0.0420	0.0160
Sum	7	0.0570	0.0160
F	11	0.0420	0.0133

Wyoming Load

Season		Alpha	Sigma
F	1	0.3200	0.0150
W	2	0.3000	0.0140
Sp	4	0.2000	0.0132
Sum	7	0.2000	0.0170
F	11	0.3200	0.0150

COB Electric Price

Season		Alpha	Sigma
F	1	0.1059	0.1362
W	2	0.0187	0.0947
Sp	4	0.0653	0.1864
Sum	7	0.0663	0.1528
F	11	0.1059	0.1362

Four Corners Electric Price

Season		Alpha	Sigma
F	1	0.1633	0.1003
W	2	0.0790	0.0889
Sp	4	0.1684	0.2397
Sum	7	0.1486	0.1773
F	11	0.1633	0.1003

Mid C Electric Prices

Season		Alpha	Sigma
F	1	0.2223	0.2184
W	2	0.0259	0.1163
Sp	4	0.0594	0.2128
Sum	7	0.1037	0.2149
F	11	0.2223	0.2184

Palo Verde Electric Prices

Season		Alpha	Sigma
F	1	0.1328	0.1095
W	2	0.1032	0.1253
Sp	4	0.0868	0.1979
Sum	7	0.1161	0.1800
F	11	0.1328	0.1095

Mid C Gas

Season		Alpha	Sigma
F	1	0.0226	0.1506
W	2	0.0039	0.0517
Sp	4	0.0114	0.0414
Sum	7	0.0089	0.0519
F	11	0.0226	0.1506

Utah Gas

Season		Alpha	Sigma
F	1	0.0123	0.0830
W	2	0.0031	0.0418
Sp	4	0.0317	0.0984
Sum	7	0.0043	0.0436
F	11	0.0123	0.0830

Hydro

Season		Alpha	Sigma
F	1	0.0806	0.0518
W	2	0.0158	0.0513
Sp	4	0.1009	0.0780
Sum	7	0.1210	0.0680
F	11	0.0806	0.0518

[20] F = Fall, W = Winter, Sp = Spring, Sum = Summer

Short-Term Correlation Parameters

The tables below present the short-term correlation parameters that are currently being used for the PacifiCorp stochastic assessments

PAC West and UTAH Load

Season		Rho
F	1	0.6793
W	2	0.4408
Sp	4	0.4701
Sum	7	0.4339
F	11	0.6793

PAC West and WY Load

Season		Rho
F	1	0.5711
W	2	0.4010
Sp	4	0.2147
Sum	7	0.3233
F	11	0.5711

COB and Mid C Electricity

Season		Rho
F	1	0.7336
W	2	0.8319
Sp	4	0.9039
Sum	7	0.6735
F	11	0.7336

COB and Four Corners Electricity

Season		Rho
F	1	0.7991
W	2	0.7513
Sp	4	0.4956
Sum	7	0.7247
F	11	0.7991

COB and Palo Verde Electricity

Season		Rho
F	1	0.8762
W	2	0.5680
Sp	4	0.8217
Sum	7	0.7286
F	11	0.8762

Four Corners and Mid C Electricity

Season		Rho
F	1	0.5397
W	2	0.6365
Sp	4	0.4535
Sum	7	0.4738
F	11	0.5397

Four Corners and Palo Verde Elecricity

Season		Rho
F	1	0.9203
W	2	0.6123
Sp	4	0.5707
Sum	7	0.9137
F	11	0.9203

Mid C and Palo Verde Electricity

Season		Rho
F	1	0.6464
W	2	0.4652
Sp	4	0.7464
Sum	7	0.4885
F	11	0.6464

Mid C and Utah Gas

Season		Rho
F	1	0.4809
W	2	0.5988
Sp	4	0.3634
Sum	7	0.8149
F	11	0.4809

PAC West Load and COB Electric

Season		Rho
F	1	0.0191
W	2	-0.0380
Sp	4	0.0855
Sum	7	0.0577
F	11	0.0191

PAC West Load and Four Corner Electric

Season		Rho
F	1	0.1456
W	2	0.0012
Sp	4	0.1371
Sum	7	0.0647
F	11	0.1456

PAC West Load and Mid C Electric

Season		Rho
F	1	-0.0389
W	2	-0.1013
Sp	4	0.0796
Sum	7	0.0003
F	11	-0.0389

PAC West Load and PV Electric

Season		Rho
F	1	0.0172
W	2	-0.0292
Sp	4	0.1299
Sum	7	0.0771
F	11	0.0172

PAC West Load and Mid C Gas

Season		Rho
F	1	0.2534
W	2	-0.2597
Sp	4	-0.0978
Sum	7	-0.0798
F	11	0.2534

PAC West Load and Utah Gas

Season		Rho
F	1	-0.1795
W	2	0.0242
Sp	4	-0.1443
Sum	7	-0.0385
F	11	-0.1795

Utah Load and COB Electric

Season		Rho
F	1	0.1036
W	2	-0.0121
Sp	4	0.0506
Sum	7	0.1200
F	11	0.1036

Utah Load and 4C Electric

Season		Rho
F	1	0.1905
W	2	-0.1335
Sp	4	0.0992
Sum	7	0.1330
F	11	0.1905

Utah Load and Mid C Electric

Season		Rho
F	1	0.0746
W	2	-0.1030
Sp	4	0.0237
Sum	7	0.0019
F	11	0.0746

Utah Load and PV Electric

Season		Rho
F	1	0.0511
W	2	-0.0599
Sp	4	0.1192
Sum	7	0.1370
F	11	0.0511

Utah Load and Mid C Gas

Season		Rho
F	1	0.1586
W	2	0.1650
Sp	4	0.0050
Sum	7	-0.1457
F	11	0.1586

Utah Load and Utah Gas

Season		Rho
F	1	-0.0920
W	2	0.0557
Sp	4	0.0103
Sum	7	-0.0189
F	11	-0.0920

WY Load and COB Electric

Season		Rho
F	1	0.0724
W	2	-0.0117
Sp	4	-0.0068
Sum	7	0.0131
F	11	0.0724

Utah and Wyoming Load

Season		Rho
F	1	0.7178
W	2	0.2200
Sp	4	0.3980
Sum	7	0.5461
F	11	0.7178

WY Load and 4C Electric

Season		Rho
F	1	0.2063
W	2	-0.1752
Sp	4	-0.0947
Sum	7	0.0363
F	11	0.2063

WY Load and Mid C Electric

Season		Rho
F	1	0.0610
W	2	0.0404
Sp	4	0.0250
Sum	7	-0.0510
F	11	0.0610

WY Load and PV Electric

Season		Rho
F	1	0.0565
W	2	-0.0222
Sp	4	-0.0744
Sum	7	0.0592
F	11	0.0565

WY Load and Mid C Gas

Season		Rho
F	1	0.2063
W	2	0.4162
Sp	4	0.0498
Sum	7	-0.0360
F	11	0.2063

WY Load and Utah Gas

Season		Rho
F	1	-0.0544
W	2	0.0592
Sp	4	-0.0054
Sum	7	0.0023
F	11	-0.0544

Mid C Gas and COB Electric

Season		Rho
F	1	0.0642
W	2	0.4557
Sp	4	0.2869
Sum	7	0.0751
F	11	0.0642

Mid C Gas and 4C Electric

Season		Rho
F	1	0.0516
W	2	0.5779
Sp	4	0.2797
Sum	7	0.0790
F	11	0.0516

Mid C Gas and Mid C Electric

Season		Rho
F	1	0.0114
W	2	0.3121
Sp	4	0.2714
Sum	7	0.0951
F	11	0.0114

Mid C Gas and PV Electric

Season		Rho
F	1	0.0738
W	2	0.3248
Sp	4	0.2466
Sum	7	0.0548
F	11	0.0738

Utah Gas and COB Electric

Season		Rho
F	1	0.2237
W	2	0.3719
Sp	4	0.1048
Sum	7	0.1571
F	11	0.2237

Utah Gas and 4C Electric

Season		Rho
F	1	0.0665
W	2	0.3165
Sp	4	0.1023
Sum	7	0.1402
F	11	0.0665

Utah Gas and Mid C Electric

Season		Rho
F	1	0.1693
W	2	0.2972
Sp	4	0.1030
Sum	7	0.1876
F	11	0.1693

Utah Gas and PV Electric

Season		Rho
F	1	0.2822
W	2	0.3043
Sp	4	0.1195
Sum	7	0.1272
F	11	0.2822

APPENDIX I – MODEL DESCRIPTIONS

INTRODUCTION

This section provides descriptions of the methodology for the MIDAS Gold Transact Analyst (MIDAS) model from MS Gerber and the PROSYM least-cost dispatch model from Henwood Energy Services. PacifiCorp used both models in the development of the IRP. MIDAS is the tool used to derive forward market prices, which are incorporated into the PROSYM dispatch model to test portfolio system operations.

MIDAS

Introduction - Wholesale Market Prices in General

Every market valuation of generation resources is significantly influenced by the underlying forecast(s) of wholesale market prices. The commodity nature of the wholesale electric market anticipates that reasonable, well-informed parties will possess different market expectations. The challenge of this IRP process is to find a path that best achieves the identified objectives irrespective of the exact level of market prices in the future. This paper provides an overview of the MIDAS model and the major assumptions.

Market Clearing Price Model Used at PacifiCorp – MIDAS Overview

PacifiCorp uses MIDAS Gold Transact Analyst, an hourly, chronological market clearing price dispatch model licensed from MS Gerber.

- The model is a representation of the entire WECC, and is comprised of all the loads, thermal and hydrogeneration, and the interconnected transmission system.
- Loads and resources are grouped according to the bulk transmission (230 KV and up) to represent known constraints and limits on electricity transfers.
- The model uses all thermal and hydrogeneration and transmission available at any given time to minimize market prices.
- Generation cost supply curves are determined for each load center based on gas/coal price projections over time.
- The model determines an efficient dispatch and import/export of generation, respecting transmission limits and wheeling rates.
- The model can also simulate the addition of various pre specified new generation resources in response to market prices. A new resource will be automatically added to the supply of resources when market prices are sufficient to recover the costs of that new resource, including capital recovery.
- The market-clearing price is set by the unit on the margin for each load center and each hour.

How the Model Determines Prices

The model utilizes the entire bulk transmission grid to earn maximum profits for generators while at the same time minimizing market prices. Several iterations are completed as the model goes through the simulation. First, the model determines supply curves in each load center without any electricity transfers. The model will, for example, determine in iteration #1 that the supply curve where load and supply match for Wyoming is $15/MWh and where load and supply match in SP15 is $60/mwh. The model may, in iteration #2, send electricity to SP15, raising the supply curve in Wyoming and lowering the supply curve in SP15.

In iteration #3, the model may decide that there are still more savings if it sends less electricity to SP15 and more electricity to COB. The model will go through several iterations, possibly 70-80, until market prices change by no more than a pre-specified amount, such as $0.10/mwh in our case.

When the load/supply balance becomes tight, a scarcity value is added in addition to the variable operating cost (fuel plus variable O&M). The scarcity factors were determined by calibrating the model against 2000 market prices, a period of scarce generation when the market commanded significant scarcity rents. As new generation comes on line and the reserve margin increases, the value of scarcity decreases dramatically.

A forecast for emission allowance credit costs is included in Appendix C. The assumption is that each company will be forced to comply with multi-pollutant legislation and install control equipment that will decrease the emission rate of their generators. But for the incremental cost of the next MWh, generators will need to include the cost of SO2, NOX, Hg and CO2 adders in their decision to generate or not and this will add a component to market prices.

MIDAS Gold Analyst Description

MIDAS Gold® Analyst™ is the leading integrated suite of PC-based analytical tools designed specifically for energy service providers. **MIDAS Gold® Analyst™** 's unique ability to combine speed, multiple scenarios, and risk analytics with the integrated capabilities to model regional market prices, operations, customers, and financials, makes it an invaluable tool in the new competitive environment. No other model is as fast, accurate, or reliable.

MIDAS Gold® Analyst™ is an integrated, fast, multi-scenario market model capable of capturing many aspects of regional electricity market pricing, resource operation, asset and customer value. It is composed of **Transact Analyst™**, **Asset Analyst™**, and **Customer Analyst™**. **Asset Analyst™** is a financial simulation model used to produce unit-specific financial results (e.g. GenCo, DisCo, and TransCo), value assets, and develop transfer pricing. **Transact Analyst™** is an hourly, multi-area, chronologically-correct market production model used to derive market prices, evaluate electricity contracts, and develop regional or utility-specific resource plans. **Customer Analyst™** is a customer valuation model used to quantify customer value, enhance marketing strategy, and analyze customer-pricing alternatives. Together, these three modules make **MIDAS Gold® Analyst™** the leading software suite for information management, decision analysis, and electricity market simulations.

PROSYM

Introduction and Overview

PROSYM is a complete electric utility/regional pool analysis and accounting system developed by Henwood Energy Services (HESI). It is designed for performing planning and operational studies, and as a result of its chronological structure, accommodates detailed hour-by-hour (or by half hour or 15 minute increments, if desired) investigation of the operations of electric utilities and pools. Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM closely reflect actual operations. PROSYM was the first second-generation chronological model, with new technology that vastly sped up the simulation process that used open standards for both input and reporting to link up with the latest software tools. Now, it is the first third-generation model, capable of analysis not only in the traditional cost-based world, but also in the rapidly evolving pools and free markets for power worldwide.

PROSYM's hourly or sub-hourly time steps can accommodate the modeling of virtually any utility or pool situation.. In modeled time step of a study period, PROSYM considers a complex set of operating constraints to simulate the least-cost operation of the utility, or least-bid operation of the pool. This simulation, respecting chronological, operational, and other constraints in the case of cost-based dispatch, is the essence of the model.

General Capabilities of the PROSYM System

PROSYM is a general-purpose simulation model capable of representing most electric load and resource situations. To perform simulations, the PROSYM system requires: at least one basic set of annual hourly loads; projections of peak loads and energies on a weekly, monthly, seasonal or annual basis for the study of any future period; and data representing the physical and economic operating characteristics (the resource mix) of the electric utility or pool, and any relevant pool or ISO rules. The size of the system being studied, and the duration of the study, are limited only by computer capabilities and not by model restrictions. The minimum duration of simulation is one week, although a day's accumulated hourly data may be easily obtained.

PROSYM Module

The PROSYM module performs the actual simulation of utility or pool operations. PROSYM has seven modes of operation: Convergent Monte Carlo, Monte Carlo, selective Monte Carlo, antithetic sampling, probabilistic, frequency and duration of outages, and deterministic. For the purposes of this study, PacifiCorp used the Convergent Monte Carlo method for simulation.

Convergent Monte Carlo

The Convergent Monte Carlo method, developed by HESI, causes carefully distributed outages throughout each period. This is a very fast method of obtaining results of multi-iteration Monte Carlo quality. This method can reduce the standard deviation of simulation values by as much as 70 percent over true Monte Carlo. Thus, far less iteration produces quite accurate results. In many cases, one iteration is sufficient to deliver the needed answers. Station random outages are scheduled in a user-defined convergence period that can be a year, month or week. It is the preferred modeling method used in PROSYM.

Hourly Marginal Cost Determination

When PROSYM executes on an hourly basis, marginal costs are determined hourly. Marginal cost is provided for the system as a whole and for each transmission area designated as a "system area". There are three cases of marginal cost determination in PROSYM:

- Case 1: When resources are insufficient to meet load, the price assigned to energy not served is used for marginal cost.
- Case 2: When dump electricity is generated, the dump price is used for marginal cost. Such a situation might occur in an area when extremely high hydro runoff exceeds the transmission area's native load.
- Case 3: When any other generating resource is the last resource dispatched to meet load in a transmission area, the incremental cost (or asking price if PROSYM is run in a bid based mode) of the resource over the user defined dispatch increment which spans the final generation level of the unit is used for marginal cost. If the station is in a different transmission area, the marginal cost is altered to account for any transmission losses or wheeling charges.

Transmission-Limited Area Modeling

PROSYM allows placing local generation requirements and transmission limits and characteristics into sub-regions called *transmission area*s. There are two possible topologies available, Star and Delta. In Star topology, all transmission areas connect into a center area called "System"; all generating resources and transactions not explicitly placed into a transmission area are in "System"; and there is only one transmission path for power flows from a source to a demand. In Delta topology, there is no center "System" area, so all resources must be explicitly placed in a transmission area; links must be declared to connect the transmission areas; and multiple paths are possible.

Each transmission area is considered attached to the main system by a transmission link. Limits and characteristics including Capacity by direction, losses, and wheeling, are assigned to the link Also, a transmission area may carry its own spinning/primary reserve requirement, over and above the overall system requirement. As system commitment / dispatch proceeds, transmission areas are dealt with separately to insure the least expensive dispatch is found without violating area constraints.

When meeting load in a transmission area, the cheapest solution for the next increment of power may be within the area or outside. However, the outside increment is viewed through a "filter" of line losses and wheeling charges. For example, if the next increment of power within the area costs 15 mills, and outside, 14 mills, but wheeling charges add 2 mills to the outside power, the cheaper solution is the 15-mill in-area power. If there are no wheeling charges but there are line losses amounting to 10 percent of power transmitted, then again, the in-area generation is more economical. However, if the transmission line is full, if there is a local generation requirement to meet, or if local spinning reserve policy requires it, the local power is used regardless of relative cost, with a corresponding effect on local marginal cost.

Another multi-area aspect to consider is that, by default, losses along transmission links are reported but not generated for. That is, if 100 MWh is needed in a neighboring transmission area, and the link from the marginal generation has a 5 percent line loss, then 100 MWh is produced in the neighboring area, 100 MWh arrives at the load, and 5 MWh is reported as lost. This is caused by the default convention that loads contain losses. The user may, however, opt to generate for line losses if not included in the load forecast.

Types of Generation Resources Modeled

PROSYM models a variety of generation resources and handles transactions, allowing representation of all standard resource types encountered in routine production cost modeling. PROSYM allows you to select from six specific types of stations; all types of resources fit into one of these categories. The six station types are:

1. Thermal - transactions/sales, generation priced at marginal cost, time-dependent units, and must-run units
2. Hydrogeneration - Conventional hydrogeneration resources or any fixed energy station or contract
3. Pumped storage - Pumped-storage type resources, exchange contracts
4. Limited energy - Limited-energy resources
5. Proxy - Stand-in "resource" representing an external event
6. Financial - Financial contracts, such as hedges, that do not involve actual electricity delivery

The specification and PROSYM's handling of these types of resources (or sales) are discussed in the sections below.

Thermal/Time-Dependent Generation

The default type of resource is used to represent conventional thermal units, transactions/sales, generation priced at marginal cost, time-dependent units, and must-run units.

Numerous variables are used to control the operation of a conventional thermal unit. A conventional thermal generation unit generally has a fuel cost and a heat rate. Typically, a thermal station is committed based on economics, dispatched based on economics, has a forced outage rate, a maintenance rate, and associated data to constrain operation of the unit to represent its physical characteristics. Data is entered to represent startup cost, variable O&M cost, and annual fixed cost of the station. Emissions data may be input for any unit that is thermal. The data specifies pounds (or kg) of a particular emission/million Btu (or GJ) of fuel consumed by the unit, pounds (or kg)/MWh produced by the unit, pounds (or kg)/hour of operation of the unit, or (in the case of NOx) a point-by-point, third-order, or exponential equation based on electricity output.

A transaction is also modeled as a station resource. In the case of a sale, its maximum capacity is given by a negative number, and its optional minimum capacity is either negative number or zero. If the commit variable indicates that the transaction is must-run, it must be scheduled, but PROSYM chooses any level of transaction between the minimum and maximum levels, depending on economics. If it is an economy transaction, the model may choose not to sell electricity in hours when revenues do not contribute above cost, or not to buy electricity when it costs more than the generating cost. The commit variable is used to force the transaction, or allow commitment at the model's discretion.

The following information about a station is input on a generating unit basis:

1. Maximum capacity of each unit
2. Minimum capacity of each unit
3. Dependable per-unit capacity
4. Peaking capacity, for use under specified conditions
5. Actual pre-specified commitment and/or unit dispatch
6. Daily charge for operating a unit for at least one hour in the day
7. Fixed O&M cost of each unit
8. The heat rate curve for a unit
9. Pre-scheduled maintenance, number of units and duration
10. Maintenance rate, for distributed maintenance/unit
11. Mean, maximum, and minimum time to repair, for outages scheduled by Convergent Monte Carlo
12. Minimum up and down times of a unit
13. Per-hour operating cost, exclusive of fuel and variable O&M cost
14. Pumped storage pumping capacity, and pumping minimum
15. Unit ramp and run-up rates
16. Unit startup O&M and fuel cost and corresponding hours

Run-of-River and Storage Hydrogeneration/Fixed Energy

Like the thermal stations described above, these stations have a maximum and minimum generating capacity, but they also have a fixed amount of energy they must use within a specified time (a week or a month). Hydro stations can be directed to operate in a manner to level the load shape served by other stations or to dispatch based on expected market price. Hydro stations are scheduled one at a time over the horizon of the week, subject to hourly constraints for minimum and maximum generation, and weekly constraints for ramp rates, and total energy. The load shape they intend to level can be set to the transmission area, control area, or overall system load.

In a peak shaving mode, the mode used by PacifiCorp in this study, a hydro station is first scheduled to operate at its minimum for all hours and the load for each hour is reduced by the amount of this generation. If this schedule is less than the week's energy, the generation is increased by an increment (for the hours with the highest adjusted loads; the loads for these hours are accordingly adjusted downward. Hourly constraints are enforced during the dispatch process. This process is continued until the total weekly generation for this station matches the specified value. Interpolation is used on the last increment.

Fixed Energy Transactions

Fixed energy transactions are a special case of hydro, and are treated similarly. PROSYM allows four fixed energy transactions: peak-shave purchase, peak-build sale, valley-take purchase, and valley-fill sale. Which transaction type is appropriate depends on whether the purchaser or the seller controls the rate and time of power delivery.

Pumped Storage Plants/Energy Exchange Contracts/CAES Units
PROSYM makes use of a value-of-energy method of dispatch. This method allows accurate results, flexibility in modeling generation / pay back resources other than pumped storage plants, and accounting for head variations in pumped storage plants. The method also provides a meaningful measure of marginal cost when a pumped storage plant is the marginal plant. The water (fuel) of pumped hydro generation is valued at the cost of pumping, allowing for net plant efficiency. Hourly reservoir levels are computed and a look-ahead is employed to prevent drawing the reservoir below the level where pumping space allows refilling to the desired level before the beginning of the next peak period.

Energy-Limited Generating Units
PROSYM allows modeling of resources that have maximum and/or minimum energy limits. These are specified energy limited in the station's description.

Proxy and Financial stations were not used in PacifiCorp's study.

Unit Commitment Logic in PROSYM
Introduction
This section briefly describes the unit commitment and dispatch logic and associated features in PROSYM. This is followed by descriptions of the separately licensed add-on PROSYM modules and their interaction with unit commitment.

PROSYM's unit commitment and dispatch logic is designed to mimic "real world" electricity system hourly operation. This involves:

1. minimizing system production cost
2. enforcing the constraints specified for the system, stations, associated transmission, fuel, and so on;

Depending upon whether PROSYM is directed to dispatch on a cost-based or bid-based manner, the minimization of the system "production cost" is based on station production cost or the station bidding prices. The following criteria are observed during the commitment process.

1. **System and local security**. PROSYM allows the user to specify three levels of spinning and primary reserve: system level, control area level, and transmission area level. The user can specify the reserve at any level or at all the levels. The unit commitment and dispatch logic not only looks in the current hour but also looks into the future hours for the possible security violation. If the de-commitment of a station will cause a reserve violation in the current hour or the future hours, the station will remain on-line.
2. **Station physical constraints**. The user can specify minimum up and down time for each station.
   - If a station was off-line in the previous hour, the logic counts the number of hours the station has been off-line and compares the number with the station's minimum down time.
   - If the number of off-line hours is less than the minimum down time, the station will remain off-line in the current hour.

- If the station can be de-committed, PROSYM's "look-ahead" logic estimates how many hours the station can be off-line. If the number of possible off-line hours is less than the minimum down time, the station will be kept on-line.
- By the same token, the station minimum up time criterion is checked if the station was on line in the previous hour. Also, the ramp rate and run up rate is considered in the de-commitment decision process. If a station with ramp rate or run up rate will be needed in a given hour, the station will be committed a few hours earlier for ramping up. Similarly, if a station is about to be de-committed, the station will ramp down and prepare to be shut down.

3. **Transmission Constraints**. PROSYM determines power flow to equalize the incremental costs of all transmission areas in the system and enforce the power flow constraints. A transmission area may import inexpensive power from its neighbors or export power to replace its neighbor's expensive power. A station may pass the other criterion tests, but if, for example, the inexpensive replacement of energy cannot reach the transmission area the station is located in, the station will not be de-committed.
4. **Limited Fuel Constraints.** PROSYM's limited fuel logic interactively works with the unit commitment and dispatch logic to observe fuel limits while economically dispatching stations. A station may be kept on-line to avoid fuel under-burn, or off-line to avoid fuel over-burn. The fuel consumption status is passed back to the commitment and dispatch logic by station shadow prices. If a fuel is over-burnt, the shadow price of the stations burning this fuel will be the "emergency" price. If a fuel is under-burnt, the shadow price of the stations burning the fuel will be the "dump power" price.
5. **Other operations constraints**. The other operation constraints include Heat Production Constraints, Transmission area minimum generation constraints, etc. The constraints are enforced in two ways: keep stations on-line or off-line or at certain generation level to meet the constraints or the constraints are quantified by shadow prices added to the commitment and dispatch prices.
6. **Economy.** PROSYM's look ahead logic can estimate how may hours that a station can be off-line in the future. The cost of the station minimum capacity in the off-line hours is compared with the startup and stop cost. A de-commitment decision is made if the startup and stop cost is less than the cost of the station minimum capacity less the replacement cost.

PROSYM has other dispatch modules that may be used. They include:

Contract Flow (Transport Logic) and Physical Power Flow (TOPS)
PROSYM's can schedule contract flow using Network Flow Programming technique (Transport logic) or physical power flow using DC-OPF technique (Transmission Oriented Production Simulation, TOPS). In both modules the power flow (contract or physical) is scheduled at every step of the unit commitment and dispatch logic to correct any possible transmission constraint violations. The transmission wheeling charges and (linear or quadratic) losses are taken into consideration in the generation dispatch.

The transport logic identifies energy trading partners and the contract path (minimum cost path), and schedules power flow to maximize the revenue. TOPS schedules physical power and corrects transmission constraint violations caused by physical power flows.

Limited Fuel Module

PROSYM's limited fuel logic works with the unit commitment and dispatch logic to economically schedule hourly power generations and to enforce the fuel limits. The fuel limits enforced by the module include hourly fuel limits, hourly pipeline limits, daily, weekly, annual fuel limits and weekly fuel inventory limits. The Limited Fuel module identifies the marginal fuel for each limited fuel station and calculates station associated marginal cost during and after the commitment and dispatch process.

Emission Module (ECOSYM)

PROSYM's emission module, ECOSYM, can calculate 14 types of emissions that can be station-dependent, fuel-dependent or both. The emissions are priced using the user provided prices, and the stations producing emission are penalized in the unit commitment and dispatch process.
In addition, ECOSYM allows the user to specify the emission allowance trading and calculate the emission allowance borrowing and banking.

Controlling PROSYM Execution

Although simple on a broad conceptual basis, PROSYM itself is quite complex. This complexity is necessary to provide the flexibility required to simulate day-to-day utility or pool operations. The model is controlled by specifying and assigning values to a broad menu of parameters. These parameters are grouped into several distinct sections in a PROSYM data set.

APPENDIX J – METHODOLOGY

INTRODUCTION

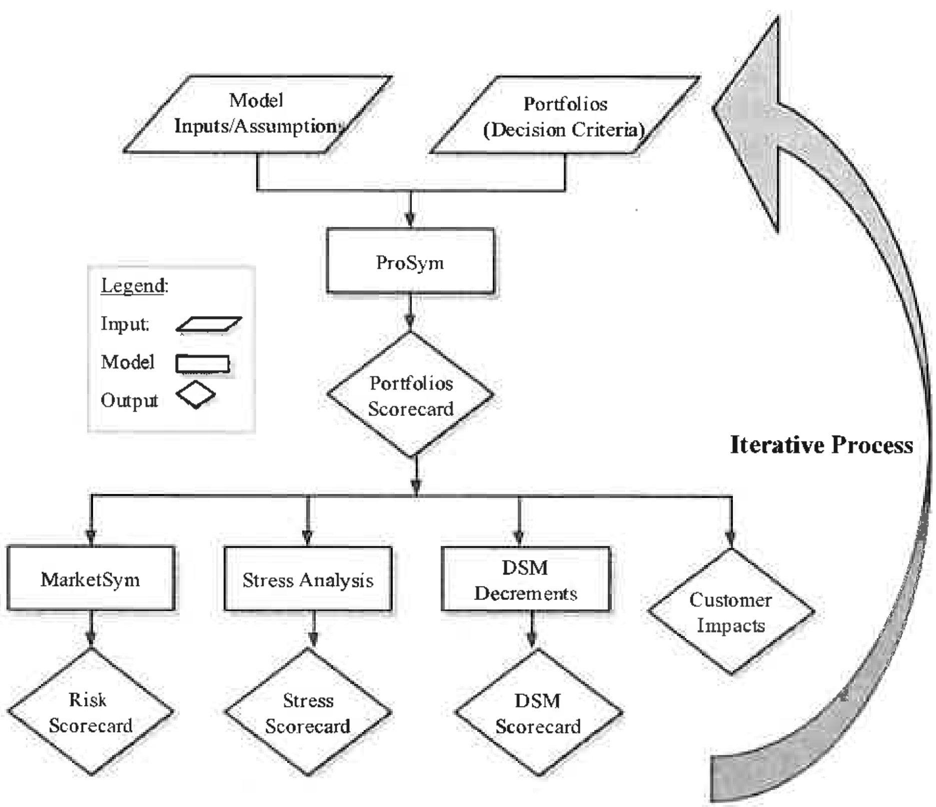
PacifiCorp's analytical approach is in many ways a response to recent events and expected changes to its operating environment. Accordingly, the approach introduces an analysis of risk in order to provide insight on the commodity price volatility described in Chapter 1. It also seeks to capture the relationships between risk factors. These relationships were critically underscored by the interplay of gas prices, electricity prices, hydrogeneration availability and high loads as they converged to create the Western electricity crisis. The analytical approach also addresses the need to model resources collectively, in portfolios, rather than in isolation. This Appendix details the analytical approach behind this IRP.

For purposes of simplification, the analytical approach is divided into three general steps:

- Portfolio Development
- Model Input Selection
- Modeling

These steps as well as a brief discussion of critical analytical assumptions is provided below. The diagram below illustrates this process:

Figure J.1 IRP Development Process



PORTFOLIO DEVELOPMENT (STEP 1)

Portfolio Selection is the first step in the analytical approach. Previous IRPs analyzed alternative resources in isolation. Rather than merely pick and choose individual assets for review, PacifiCorp employed a portfolio selection process (described below). The portfolio approach enhances previous methodologies by evaluating individual asset costs and their interactions with other members of the portfolio. The modeling approach, therefore, revolves around the development and subsequent analysis of complete portfolios of resources. The process by which portfolios were developed is summarized as follows:

- Portfolio Requirement Criteria: A standard set of criteria was established. All portfolios must adhere to these criteria.
- Portfolio Generation and Refinement: To develop and then refine the resources in portfolios an iterative process was performed.

The information below details the development process. Additional information regarding specific portfolios can be found in Chapter 6.

Portfolio Requirement Criteria

The Portfolio Requirement Criteria consist of logical rules for portfolio development. The rules assure portfolios contain practical resource configurations conforming to system operational requirements and government regulations. Unless otherwise noted, all portfolios considered in the IRP met the following criteria:

- Compliant with all federal, state and local requirements
- Compliant with EPA and other environmental requirements
- To the extent possible, without unduly burdening ratepayers, be consistent with other public policy values that may not necessarily be embodied as a specific regulatory requirement e.g. renewable policies or technology preferences
- To the extent of not unduly burdening ratepayers, the portfolios should be diverse and include a mix of demand- and supply-side measures
- Be technically feasible, i.e. based on tried and proven technologies
- Can be acquired in time to meet load requirements
- The environmental implications associated with the potential options must be realistic e.g., siting of resources to ensure PacifiCorp is:
  - Not trying to achieve the impossible, e.g., new transmission built across a national monument
  - Managing within environmental limits
  - Helps to minimize the Company's commodity risk exposure to electricity market volatility
  - With respect to rate-based assets, allows PacifiCorp's rate of return

Portfolio Generation and Refinement

Portfolio generation and refinement was performed through an iterative process in lieu of an automated optimization tool. Currently, no automated tool exists. The following information describes the step-by-step process.

1. **Assumptions**: Basic, modeling assumptions must be defined. These assumptions capture the characteristics of PacifiCorp's system and portfolio alternatives. For example:
   - System topology, e.g., 22 bubbles or distinct and constrained transmission areas
   - Existing resource operating characteristics including life of plant or contract
   - Forecast of various drivers, e.g., loads, market prices, etc.

Details regarding all of the assumptions can be found in Appendix C.

2. **Portfolio Design Rules**: Design rules were established as guidelines for selecting assets to fill each portfolio. A critical rule was that of achieving a 15% planning margin by fiscal years 2006/07. The planning margin is the target reserve level assumed to provide sufficient future resources to cover forced outages, provide operating reserves, regulatory margin, and demand growth uncertainty.[21] The reserve is the amount of resources expected to be available during the system peak less the forecast peak load for the whole system plus the net of the long term sales and purchases. Additional rules include:
   - Net short position limited to less than 5% of the hours in any year
   - Replace known plant retirements with either a replacement plant or firm, long term purchase contracts. Filling the gap occurs thereafter
   - Preferred balance of plant type (base vs. peaker) –Selections to be made based on a capacity factor screening preference order as follows:
     - Short position exceeds 80% of hours: base load coal or combined cycle
     - Short position exceeds 70% of hours: combined cycle
     - Short position is less than 30% of hours: simple cycle CT (peakers)
     - Short position less than 5% of hours: demand reduction, seasonal shaped purchases.

3. **Peak**: The Peak System requirement must be determined in order to define the overall capacity requirement for the system and add agreed planning margin to determine maximum capacity requirement for the system.

4. **Gap**: Both the resource gap and the trends for the system must be determined by modeling dispatch of the system with access to markets switched off and all available resources assumed to be must-run. Furthermore, only firm transmission rights were assumed to be available. This results in a plotting of the Load Duration curves for the system split:
   - East/West
   - HLH/LLH
   - Year on year for first 10 years of the plan

[21] Planning margin is calculated according to the following formula: 115% times (Peak Load plus Sales minus Purchases).

5. **Alternatives**: Alternative portfolios must be defined to fill the gap. Alternatives must include practical details such as plant location and the transmission costs to get energy to load centers.[22] These portfolios meet the minimum criteria described above and also match professional judgement on what the range of "practical" alternatives are. From this, a "base-case" or "short-list" of portfolios will begin to surface and will be subject to further refinement.

6. **Initial Modeling**: Portfolios are run through the complete suite of models described below. The results help to determine:
   - Impact on system peak and the planning margin achieved
   - The impact on the resource gap – done by plotting the Load Duration curves for the system split as follows:
     - East/West
     - HLH/LLH
     - Year on year for first 10 years of the plan
       - The risk profile for the portfolio to review the price volatility of the portfolio i.e. exposure to market and overall variability of the Present Value Revenue Requirement (PVRR).
       - The impact of the portfolio on
     - Customer's retail rates
     - Shareholder value, i.e., Company earnings, capital requirements and cash flow

The Portfolio results will be juxtaposed to the Portfolio Requirement Criteria and result in the development of further refined portfolios. Steps 8 and 9 outline the iterative process for such refinement.

7. **Review**: Selection criteria for the iterative refinements and additional portfolio development include a review of the overall resource adequacy and the portfolios ability to meet the minimum criteria based on the following managed changes or variations to the portfolios:
   - Review the planning margin – increase and/or decrease the margin to seek an optimal reserve
   - Review technology type e.g. coal, gas, DSM or renewables
   - Alter the balance of plant type (e.g. base vs. peaker)
   - Alter the system net short position
   - Note: DSM will be considered for all shortfalls but sought out in particular load shaping and peaking opportunities.

Repeat Step 7 for the new or revised portfolios. Note: for the purposes of time efficiency in the initial portfolio stages only run the portfolios through the PROSYM model to determine the PVRR. Once the PVRR range is clearer, following the initial portfolio iterations, the selected portfolios can be run through all models.

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[22] More general location and pricing assumptions were associated with the RPS and profiled wind components of portfolios. Common to all portfolios, these assumptions could not affect comparative rankings.

8. **Additional Resource Options:** Once the portfolio selection has been iterated to a short list of portfolios, the portfolios will be reviewed to calculate the value of DSM and the addition of any further DSM product options. The additional DSM value will be determined by decrementing the load forecast by 150 MW and 300 MW with 3 different load factors for each decrement (a total of 6 additional model runs). This will result in PVRRs at 2 levels of additional DSM with various load factors. These results will be used as a target value, load and load shape for additional program evaluations. A discussion of the decrement process is available in Appendix G.

MODEL INPUT SELECTION (STEP 2)

The portfolios generated above contain a number of resources with diverse locations, fuel types and operational characteristics. Components of each portfolio have complex interactions. A large and detailed range of inputs is required to simulate the risks and revenue requirements of each portfolio. Developing and understanding these inputs is a critical element of the analytical approach.

An overview of the major modeling inputs is provided below. Additional input information can be found in Appendix C.

System Topology

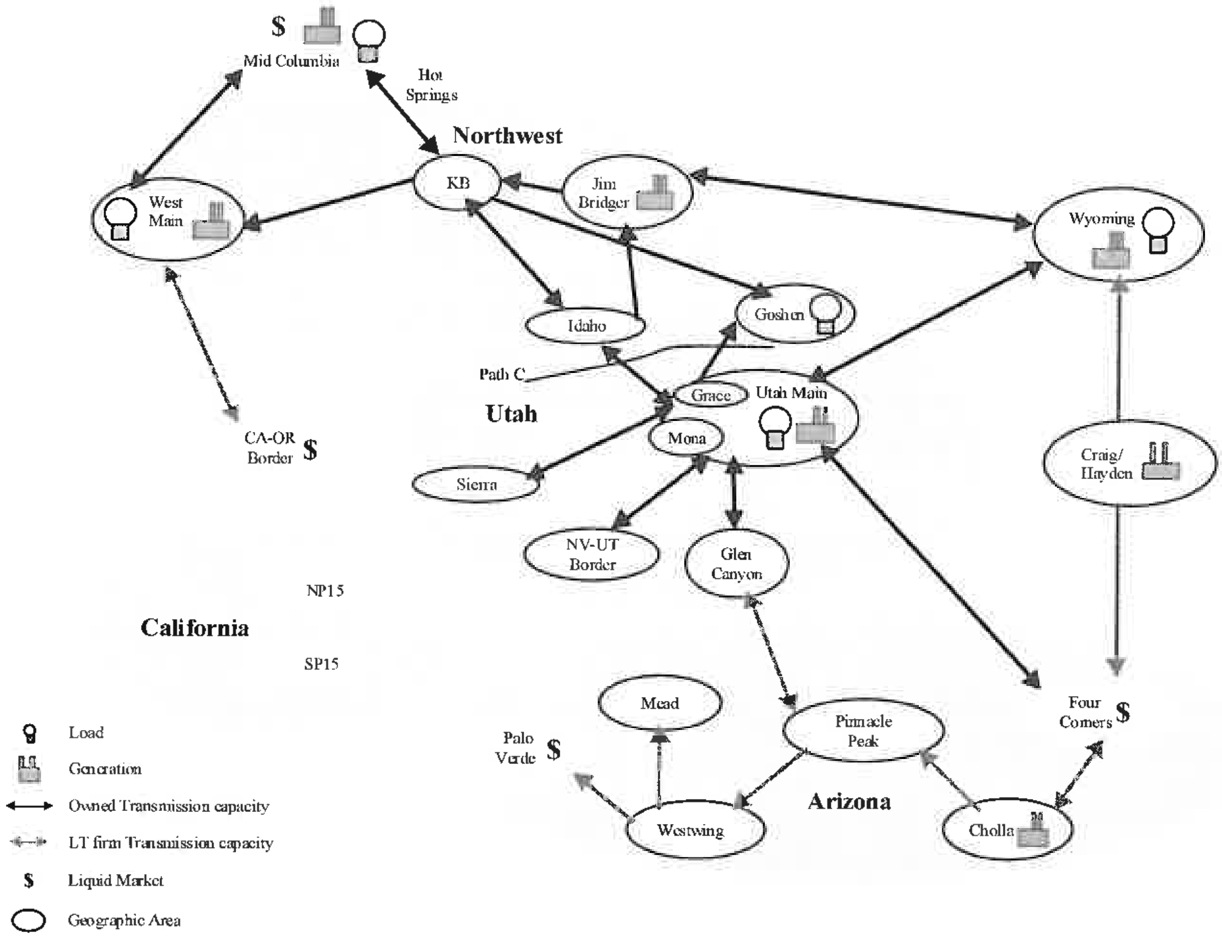
PacifiCorp staff developed a topology for this IRP that reasonably reflects the PacifiCorp system. The topology is shown in Figure J.2.

The development of this topology involved defining: the loads associated with each bubble, the existing resources located in each bubble, the characteristics of each resource, and transfer capability of the links between the bubbles, etc. In order to model the interaction between the PacifiCorp system and the WECC markets, the topology captures interactions at the following trading points:

- Mid Columbia (Mid-C)
- California/Oregon Border (COB)
- Harry Allen
- Mona
- Palo Verde

An analysis of the current and projected depth and liquidity of these markets was done to determine market size and availability characteristics for the model.

Figure J.2 IRP Topology



Market Pricing Forecasts

Long-term commodity price forecasts are critical model inputs. PacifiCorp developed its forecasts using MIDAS Gold Transact Analyst, an hourly, chronological market clearing price dispatch model licensed from MS Gerber. Detailed information regarding MIDAS is provided in Appendix I.

Resource Operating Cost

Operating costs are used by PROSYM to dispatch resources as well as simulate market purchases and sales. Operating costs include fuel, variable operation and maintenance cost, start-up cost, wheeling and emissions costs. All of these costs are used in dispatching the units. Emissions costs only above the projected cap for the various pollutants are used in the final cost analysis. The PROSYM model runs develop variable electricity costs incurred in serving PacifiCorp's load.

If there is electricity available in the WECC that can be purchased at prices lower than running PacifiCorp resources, the model will make the least cost dispatch decision and purchase from the market to meet load. If PacifiCorp has excess electricity with operating cost less than the WECC market, the analysis will cause those resources to run and sell the excess in the WECC spot market. Therefore, the variable costs will include fuel costs incurred in making spot market sales, spot market purchases, and proceeds from revenue associated with secondary sales.

Resource Reliability

Equivalent forced outage rates were assumed for new resources and taken from the history of existing resources for purposes of modeling. PROSYM then modeled the variability around these numbers.

Transmission and Development Costs

PacifiCorp used actual development opportunities as its template for determining transmission and development costs. A necessary component of the calculation of each portfolio's PVRR, these costs are a critical model input.

Scenarios

Model assumptions for scenario risks originally input into the model are revised and tested in order to observe portfolio performance under different scenarios and stress conditions. Accordingly, stress tests require each set of scenarios to be entered into the model.

MODELING (STEP 3)

The analysis process begins by selecting portfolios for evaluation (Step 1) and delineating critical inputs (Step 2). This vast collection of data is then modeled using the 6-step approach detailed below:

1. PROSYM, an hourly least cost dispatch model, incorporates the price forecasts and a wealth of transmission and operational information to simulate PacifiCorp's system. From this data PROSYM determines the resulting revenue requirements.
2. The results of the simulations are brought into the Consolidation model. Within this model capital and a range of other electricity costs are combined with net electricity cost output from the PROSYM model to calculate the PVRR of each portfolio.
3. MarketSym gathers the various risk parameters and through a stochastic process simulates one hundred different price scenarios.
4. The 100 scenarios developed from MarketSym are then run through a simplified topology version of the PROSYM model and re-dispatched to produce a range of PVRRs for each portfolio.

Results are then collated to produce:

5. Customer rate impacts.
6. Portfolio, stress and risk scorecards from the model output

PROSYM

The PROSYM model takes the market forecasts developed in MIDAS. PROSYM then uses a production cost model, simulating the operation of PacifiCorp's system. It employs a sophisticated relational database technology that operates in conjunction with this multi-area, chronological, production simulation model.

The types of information managed by the database include the data necessary to correctly consider the performance of the PacifiCorp system and portfolio options. These include:

- individual electricity plant characteristics,
- transmission line interconnections and transfer capability ratings,
- forecasts of additions and resource fuel costs, and
- forecasts of loads for each of the retail load regions served by PacifiCorp.

PROSYM simulates, with hourly detail, the operation of the individual generators, and control areas (also referred to as transmission market areas) to meet the fluctuating loads within the PacifiCorp system. The simulation takes into account various system and operational constraints. It uses a variety of methods to analyze the system, including a Monte Carlo methodology to incorporate individual unit forced outages. Output from the simulation is generated in hourly, station-level detail and analyzed. A summary of the output is available in Appendix E.

Consolidation Model

The Consolidation Model is an Excel workbook that combines the operating cost results from PROSYM with the revenue requirement of new capital additions to provide an annual revenue requirement projection for each portfolio. The net electricity cost from PROSYM includes electricity supply system costs for fuel, variable plant O&M, start-up costs, market contracts and spot market purchases and sales. Additional costs calculated outside of PROSYM, but included in the consolidation model, include DSM costs, renewable green tags and production tax credits, emission allowance costs or credits, and all of the revenue requirement costs associated with adding incremental investment in new resources and new transmission.

All annual values are determined in nominal, or escalated, dollars. The revenue requirements for the new resource and transmission capital additions are included as escalated "real-levelized" revenue requirements. The emission allowance impact is calculated in the Consolidation Model by comparing the tons emitted, as determined by PROSYM, subtracting PacifiCorp's estimate of future levels of tons allowed and multiplying it by projected emission allowance costs/ton.

The consolidation model does not include certain costs that are deemed to be common to all IRP portfolios. The excluded costs are existing generation assets' capital revenue requirements, existing generation assets' fixed O&M, CAI costs, hydrogeneration relicensing costs, and other non-electricity supply costs such as distribution, transmission and general plant capital and fixed operating costs.

The consolidation model calculates the Present Value Revenue Requirement (PVRR) of the annual combined revenue requirement, described above, for the 20-year analysis period (FY2004 – 2023) for comparison among portfolios.

The consolidation model also calculates the revenue requirement utilizing the traditional (nominal, instead of real levelized) revenue requirement calculation on capital additions for looking at the IRP-related customer impacts assuming traditional ratemaking treatment.

MarketSym

Using the dispatch model as a foundation, MarketSym incorporates price forecasts generated by MIDAS (discussed in Appendix I), the risk components described in Chapter 3 as well as the operational information simulated by PROSYM. Within MarketSym risk factors vary using a Monte Carlo simulation of each stochastic process. Details regarding this approach are provided in Appendix H. Following this process, MarketSym produces 100 different price scenarios. The risk analysis is performed using the distribution of the 100 outcomes.

While both MarketSym and PROSYM employ a Monte Carlo simulation, its importance to PacifiCorp's analytical approach becomes most apparent in MarketSym's risk analysis. The Monte Carlo simulation's iterative process captures the random nature of the Stochastic Risks identified in Chapter 3. Simpler analytical methods might only model the mean or expected value of a parameter. However, understanding risk requires understanding the likelihood of deviations from that expected value. The Monte Carlo approach helps identify the probability and thus risk of different outcomes. Furthermore, the simulation incorporates the interactions between risks. The interaction between risks is potentially as important as the individual variability of the risks alone. Finally, the Monte Carlo simulation uniquely provides insight on the non-linear nature of the risks that PacifiCorp faces. Less sophisticated analytical tools often ignore non-linear relationships and consequently lead to incorrect conclusions. Such conclusions can be particularly costly since non-linear relationships often result in a greater than expected extreme events. Such extreme (or asymmetrical) outcomes were strikingly observed during the Western electricity crisis described in Chapter 1.

Customer Impacts

The IRP customer impacts calculation includes only the $/MWh rate impacts associated with the IRP "footprint" as compared to a total company historical $/MWh (CY 2001 actual retail $/MWh was used for comparison).

The IRP footprint includes electricity supply system costs for fuel, variable plant O&M, emission allowance impact, start-up costs, market contracts, spot market purchases and sales, and DSM costs. It also includes all of the revenue requirement costs associated with adding incremental investment in new resources and new transmission. However, the IRP footprint does not include certain costs that are deemed common to all IRP portfolios. The excluded costs are existing generation assets' capital revenue requirement, existing generation assets' fixed O&M, CAI costs, hydrogeneration relicensing costs, and other non-electricity supply costs such as distribution, transmission and general plant capital and operating costs.

The IRP Customer Impact Calculation:

1. A Portfolio's \$/MWh is calculated annually by dividing the total revenue requirement of the IRP footprint by the IRP load projections.
2. Each year is compared with the previous year's \$/MWh to derive the \$/MWh increase. This \$/MWh increase is then divided by calendar year 2001's actual retail rate of \$48.97/MWh. The calendar year 2001 \$/MWh was chosen as a benchmark anchor to which all other years are compared.
3. This provides an "indicative" percentage increase attributed to the IRP portfolio for that year.

Because the IRP excludes the costs common to all portfolios, the customer impacts calculation is only relevant when comparing one IRP portfolio against another. While the IRP customer impacts calculation provides yearly directional implications of rate changes associated with IRP, it can not provide a projection of total company customer impacts because it is only a portion of the total company revenue requirement, as detailed above. Likewise, the IRP customer impacts are a consolidated company look assuming immediate ratemaking treatment and make no distinction between current or proposed multi-jurisdictional allocation methodologies.

Scorecards

Portfolio Scorecard

The portfolio scorecards pull information from the Consolidation Model and summarize the outputs. The scorecard does not include the complete data set. Rather, it provides a simplified snapshot useful for comparative purposes. In the scorecard the following items are compared:

- **PVRR – Present Value Revenue Requirement**. This is calculated over the 20-year period.
- **Capital Cost**. Capital costs represent the capital, in 2002 dollars, needed to develop the portfolio
- **Emissions**. The following information about emissions is presented:
  - PVRR from 2004 - 2023
  - Thousands of tons emitted for CO_2, SO_2, NO_x, Hg from 2009 - 2023
  - Percent above or below the cap for each pollutant from 2009 – 2023
- **Market Purchases**. Market purchases are expressed with two values: % of load served and aMW. Each is calculated over the 10 year period starting in 2004 and concluding in 2013
- **Market Sales**. Market sales are expressed with two values: % of sales as a function of owned generation and aMW. Each is calculated over the 10 year period starting in 2004 and concluding in 2013
- **Unit Capacity Factors**. Unit capacity factors represent the utilization rate for each resource. The factors presented in the score card are taken from 2014. All new resources are on line by 2014. Therefore, the factors provide clearer information for comparative purposes.
- **Transfers**. Transfers represent the East-West and West-East transfers expressed in MWhs for the periods of 2004 and 2014. Furthermore the percent increase/decrease in transfers relative to 2004.

Stress Scorecards

Stress scorecards provide the same kind of information as the portfolio scorecard discussed above. However, the output of the stress scorecard is taken from model runs in which the base assumptions of Scenario Risks are purposefully changed. As such, stress scorecards provide for portfolio comparisons of different scenarios or stress conditions.

CRITICAL ASSUMPTIONS

A comprehensive list of the assumptions used in this analysis is available in Appendix C. The assumptions below are particularly important and merit additional discussion.

Market Access Assumptions

Liquidity and physical transmission limitations constrain market access. Discussed in Chapter 5, the market is a valuable resource. Therefore, assumptions regarding market access are important to simulating realistic dispatch decisions.

Transmission

Access to market is restricted to PacifiCorp's physical transmission limitations. These limitations are captured in the system topology within the model. PacifiCorp's firm transmission rights allow market access in the West up to the liquidity constraints discussed below. East sales fall within two tiers. The first tier includes sales up to 350 MW. Such sales reach market over existing, firm transmission rights. Like the West, first tier sales are unburdened by additional transmission costs. Additional sales (second tier) are allowed. They incur short-term transmission procurement and congestion charges.

Liquidity

Liquidity limitations affect PacifiCorp's ability to balance its system in the market at a reasonable cost. Liquidity costs and limitations are observed in the bid-ask spread, price impacts or 'slippage' and other trading frictions. Estimations of future liquidity are difficult and somewhat subjective. Such frictions vary by market hub, lead-time and the size of the position to clear. Building to a 15% margin over the forecast peak load, PacifiCorp has substantial balancing requirements in non-peak periods. Liquidity is therefore an important modeling consideration.

To capture the known but subjectively defined frictions associated with market liquidity, PacifiCorp's market access is capped as follows:

- 250 MW at COB
- 250 MW at Mid-Columbia, and
- 500 MW at Palo Verde

Such limits help deter impractical model dispatch decisions and appear consistent with historical practice. All market transactions outside of existing long-term contracts are subject to this limitation.

RPS Assumption.

Initial portfolios included a common assumption that PacifiCorp would meet the proposed federal Renewable Portfolio using a flat contract priced at $50/MWh with capacity increasing by 0.6% of retail load each year. The RPS is discussed in greater detail in Chapter 3. The major points included as assumptions in the study were as follows:

- Begins in 2005 at 1% of total retail sales adjusted for existing hydrogeneration and renewable generation
- 1% grows by 0.6% each year until reaches 10% of total adjusted retail load by year 2020
- Modeled as a flat, annually increasing contract priced at $50/MWh. Contract price includes cost of transmission, integration, shaping, and firm delivery to main load centers.
- The RPS obligation is divided equally between the East and West control areas of the system.

Subsequent portfolio iterations realized superior PVRR performance when meeting this requirement with profiled wind. Therefore, the flat contract was replaced with profiled wind in the Diversified I, II, III and IV portfolios. The Renewable Portfolio, with a substantially greater wind commitment, contains both the flat contract and profiled wind.

Wind technology is assumed to decrease in per unit cost as manufacturers achieve greater scale. Accordingly, capital costs for RPS resource additions are assumed to decline at a rate equal to inflation.

DSM Assumption

Each portfolio also includes a common assumption for a combination of Class 1 and Class 2 DSM. Class I dispatchable programs represent Commercial and Residential Air Conditioning load control programs in Utah. Class 2 programs are spread throughout the system and represent a combination of different programs with total levelized costs under $40/MWh. Programs are not included for Oregon since the Energy Trust of Oregon will implement future programs.

The major points included as assumptions in the study are as follows:

- Dispatchable load control program fully implemented to 90 MW peak capability by 2006.
- Class 2 DSM programs modeled as reduction to load shapes. Multiple program shapes are combined by load center.
- Class 2 program amounts are increased by 8.5%, average distribution level losses.

5% Build Requirement

Based on input from the public process portfolios were designed to limit expected spot purchases to 5% or less of each year's hours.

Public comments originally requested building to cover 100% of the position. PacifiCorp believes building or buying to cover 100% of the position (the needle peak hour) is excessively conservative; EFOR alone can account for more than 5% for the duration.

The 5% limitation provides intuitive benefits associated with power price volatility. Power price volatility can be considerable. It is true that minimization of power price risk favors being long power more often than being short since prices are unbounded on the upside, but cannot be negative under current market rules. However, a long position, or even a 100% coverage position, requires either more owned or controlled capacity or a large amount of both shaped purchases or call optionality. These positions can be structured and can be cost effective, but this is a very fine level of detail to be shown in an IRP.

The 5% limitation is not inconsistent with a prudent spot market exposure, which PacifiCorp is now successfully managing. Recent market experience supports this. Filling the 5% short with peak hour block purchases will create shoulder hour length that will have a high probability of being surplus. This relatively small short position (approximately 5%) is favored on the basis of prudent commodity risk management.

<u>Additional Critical Assumptions</u>

The following assumptions are also critical to the analysis methodology and are common to all portfolios.

- The plan is assumed to cover a 20-year time period where no resources are added after 2013
- System transmission includes only firm rights to ensure that new and existing resources are always available to provide service.
- There is an hourly operating margin of 15% which is separate from the planning margin and consists of plant equivalent forced outage rates (EFOR), spinning and non-spinning operating reserves, contingency reserves (5% hydrogeneration and 7% thermal)
- Plant life is consistent with stipulated Plant Depreciation Study with the exception of Naughton that retires in 2022.
- All hydrogeneration plants are relicensed but the analysis includes reduction in energy and plant flexibility as estimates for possible future operational changes.

INTEGRATED RESOURCE PLAN CAPITAL REVENUE REQUIREMENT METHODOLOGY

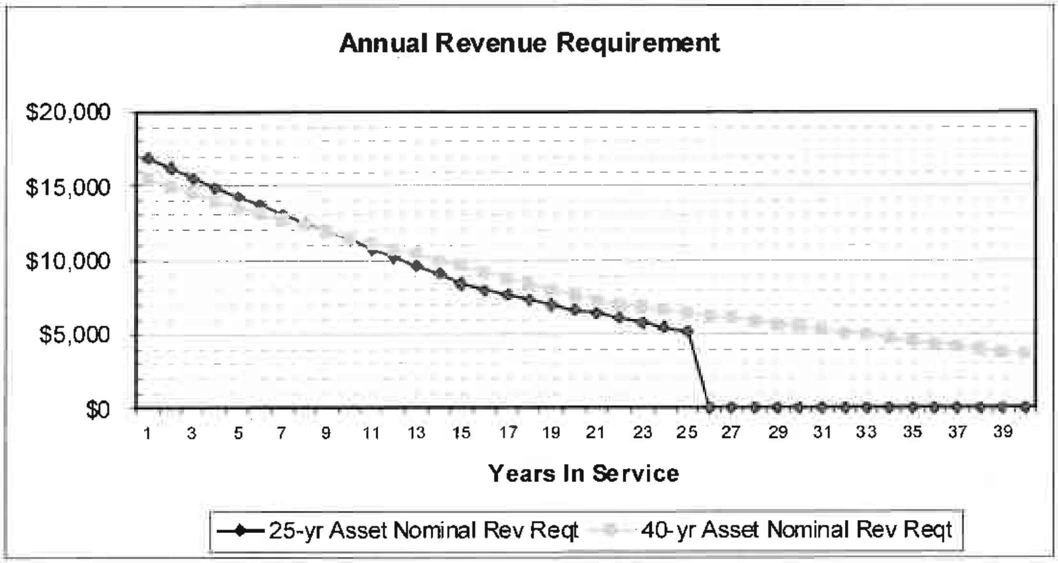
<u>Introduction</u>

PacifiCorp's IRP calculates and compares the revenue requirement of potential future resources to determine the best set of resources to meet future load projections. The IRP financial analysis includes both a variable and a fixed component of revenue requirement. The variable component includes total company fuel, variable O&M, spot market purchases and sales, start-up costs and the variable cost of purchase contracts. The fixed component includes DSM costs, incremental fixed O&M and the real levelized revenue requirement of new generation and transmission capital.

<u>Nominal Capital Revenue Requirement</u>

Traditional capital revenue requirement is largest at the beginning of the asset life and declines over time as ratebase is depreciated. Capital revenue requirement includes depreciation expense, return on ratebase, income taxes and property taxes. Figure J.3 depicts the traditional nominal capital revenue requirements for a $100,000 asset with a 40-year depreciation life and for a $100,000 asset with a 25-year depreciation life.

Figure J.3 Capital Revenue Requirements



The capital structure used above and in the IRP is based on the Utah Rate Order Docket No. 01-035-01, issued September 10, 2001. It consists of the following components from which the 7.5% discount rate used in the IRP analysis is derived.

Table J.1 Capital Structure Components

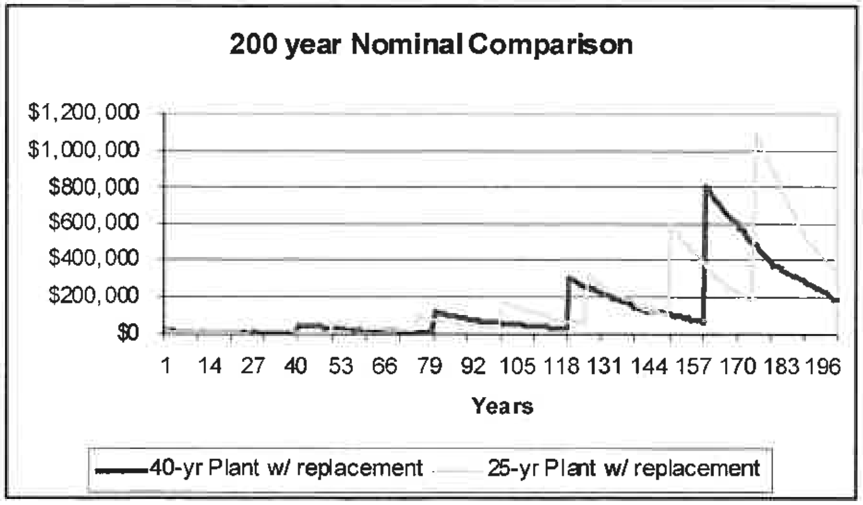
	Capital Structure %	Cost %	Post Tax Weighted Cost %
Debt	49.2	6.991	2.088
Preferred Equity	3.2	6.182	0.198
Common Equity	47.6	11.000	5.236
Structure Total	100.00	8.873	7.522

Nominal Revenue Requirements Inadequate for Comparison

Nominal capital revenue requirement is limited in its ability to adequately compare one type of resource asset against another. This is particularly true when the resources being compared have lives of different lengths, or if the resources are placed in service in different years. For example, the design life of a new pulverized coal generating plant is 40 years, while a simple cycle combustion turbine is 25 years. An analysis mismatch occurs unless an adjustment for end-life effects is made.

Another alternative, although not practical in this case, is to extend the analysis period to a length of time that results in the "least common denominator" analysis period. One could illustrate this point with an extreme example. It would take a 200-year analysis to make an equivalent comparison between the 25-year asset and a 40-year asset. The "least common denominator" analysis period would result in eight 25-year assets and five 40-year assets so that the analysis ended with the end-life of both assets. Figure J.2 shows a full 200 years of nominal revenue requirements for a series of 40-year and 25-year assets. In this example, the Present Value of Revenue Requirements (PVRR) of both assets is exactly the same. Therefore, if all else were equal in this example, one would be indifferent over this 200-year analysis period between owning a series of 25-year resources or owning a series of 40-year resources.

Figure J.4 200 Year Nominal Comparison



Compiling a 200-year analysis is not practical, but it does illustrate a point. If one is indifferent between assets when considering an "equivalent" analysis period, then what are the results one gets when looking at a more practical analysis period, say 20 years, as is used in this IRP. Figure J.5 shows the cumulative PVRR of the above revenue requirements used in Figure J.4. (Cumulative PVRR is derived by taking the present value of each year's revenue requirement and adding it to the sum of the previous years' present value of revenue requirement; all discounted at 7.5% to a common time.) Only the results of the first 45 years are shown in order to highlight the earlier years. Over an extended analysis period (200 years), the PVRR of both assets is the same.

Figure J.5 45 Year Cumulative PVRR - Nominal

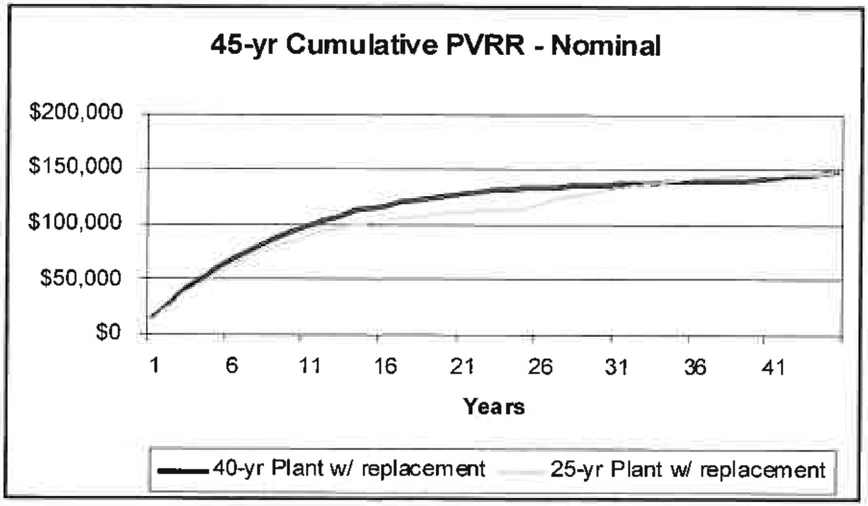


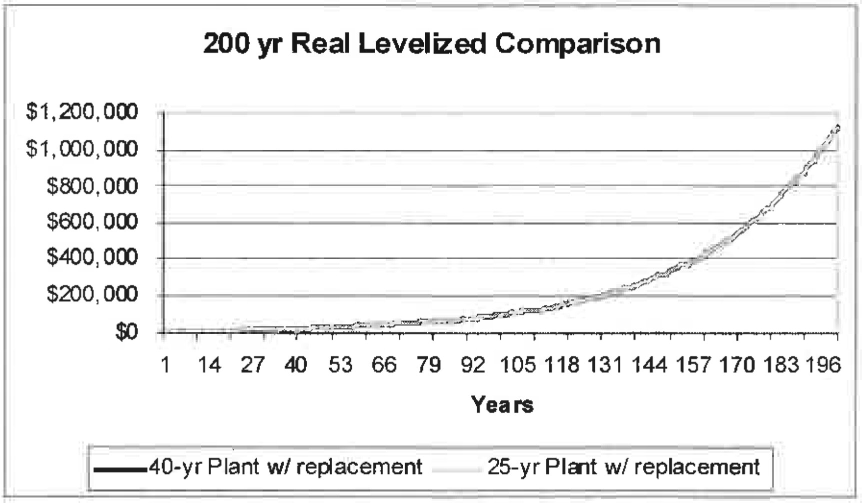
Figure J.5 clearly illustrates the problem with using nominal revenue requirements for comparing different types of resources. By definition, these assets were valued such that one should be indifferent. However, as can be seen, depending on the length of the analysis period, the nominal revenue requirement has created a valuation gap between the 40-year asset and the 25-year asset's revenue requirement. This could lead to misleading conclusions regarding the comparative cost of one resource versus another. Nominal revenue requirements, without some kind of end-effects adjustment, could result in incorrect analysis findings.

End-effect adjustment calculations can be challenging as well. For example, within a 20-year analysis period, what is the proper adjustment to a 40-year asset and a 25-year asset's cost that will place the analysis on equal footing? Should the adjustment be made to all years, or just the last year? Should the net asset value come into play, or should market valuations determine the adjustment? The answers may be as varied, as there are methodologies that could be employed to calculate the end-effect adjustment. There is an easier approach that allows for comparative analysis between resource options. It consists of utilizing real levelized capital revenue requirement.

Real Levelized Revenue Requirement

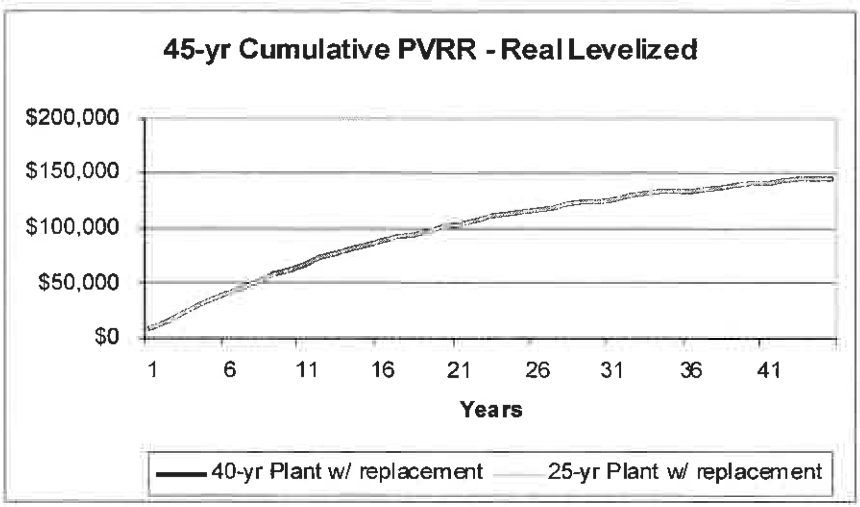
Real levelized revenue requirement is a methodology for converting the nominal year by year revenue requirement into a revenue requirement starting value, that when escalated over the same time period, will result in a revenue requirement projection that has the same present value as the nominal year by year revenue requirement. The shape of a real levelized revenue requirement is that it starts out lower in the initial year and increases at the rate of inflation. Unlike nominal revenue requirement projections, when a resource is replaced at the end of it's initial life, the revenue requirement does not take a huge jump, but continues at the rate of inflation. This coincides with the projected revenue requirements that would be calculated for a new plant being constructed at the then escalated cost. An explanation of how real levelized revenue requirements are calculated is addressed in a later section. Figure J.6 shows the real levelized revenue requirement for the same two assets that where shown in Figure J.4.

Figure J.6 200 Year Real Levelized Comparison



Because Figure J.6 uses the same assets as Figure J.4, the PVRR of the revenue requirements are the same for both assets; hence the real levelized revenue requirement values for each resource are the same each year. As mentioned earlier, the replacement of the resources throughout time does not create huge jumps in revenue requirements. Figure J.7 is the same representation as Figure J.3, except that here again, the results are presented using real levelized revenue requirements. One can see that it doesn't matter how long the analysis period is, the comparative revenue requirement valuation is the same at any point in time.

Figure J.7 45 Year Cumulative PVRR – Real Levelized



So far, the two resources shown have been placed in service on the same date and have been priced to come to the same PVRR over an "equivalent" extended analysis period. This has been solely for the purpose of creating a case that shows that assets of equivalent cost should reflect that equivalent cost, regardless of how long the analysis period is. Real levelized revenue requirements provide such a case. The advantage of using real levelized revenue requirements is also extended to an analysis that compares various resources with various lives and various in-service dates. Real levelized revenue requirements will capture the comparative economic costs with respect to one set of resources being compared against another, without the need for end-effects adjustments.

Comparison to Market Purchases

The year by year nominal capital revenue requirement in Figure J.3 shows the front-end loaded revenue requirement for capital investment. How does this compare with the alternative of market purchases? Any analysis period short of a full asset life-cycle analysis will overstate the capital revenue requirements in the early years, while leaving the lower cost later years out of the analysis. With IRP utilizing a 20-year analysis period, using nominal revenue requirements for resource capital will overstate the comparative cost of long-lived resources.

Restating the issue a different way, consider two groups of customers in a rising market price environment. Customer Group A will get to use and pay for a 40-year resource during the analysis period, say, the first 15 years, and Customer Group B will get to use and pay for the resource during the remaining plant life, or 25 years. Without some kind of adjustment, traditional or nominal revenue requirements would cause Group A to pay all the higher cost years, when market price is lower, while Group B would get to pay for all the lower cost years when market price is higher. This is hardly a fair allocation of resource costs among Customer Groups A and B when comparing the resource cost to market purchases.

Absent 20/20 foresight, any analysis methodology will have its challenges; however, utilizing real revenue requirement for capital is an improvement over nominal revenue requirements for comparing resource alternatives with market purchases when the analysis period is shorter than the life of the resource being considered.

Real Levelized Revenue Requirements Calculation

Table 2 (included after the Summary and Conclusion section) shows an example of how real levelized revenue requirements are calculated. The example shows an asset with a 15-year life.

- The present value of the nominal revenue requirements serves as a starting point.
- A "real" discount rate is then calculated by removing the inflation component from the discount rate.
- This real discount rate is used to calculate a levelized payment from the present value of the nominal revenue requirements…hence the name "real levelized."
- The effects of inflation are added back in by escalating the real levelized payment each year by the inflation rate.
- The present value of the escalated real levelized revenue requirements is equal to the present value of the nominal revenue requirements.

Summary and Conclusion

The IRP financial analysis covers a 20-year forecast period. During this forecast period, the IRP is comparing the alternative resources available to determine the best overall solution to match resources with projected load. Because many of the potential resources have long economic lives of various lengths, which extend beyond the analysis period, appropriate methodologies must be used to capture the comparative costs of such capital-intensive investments.

Nominal capital revenue requirements consist of larger values in the earlier years and decline as ratebase is reduced by asset depreciation. If the asset's life extends beyond the analysis period, this front-end loading will cause an over valuation of the comparative revenue requirements. An end-effects adjustment could be made, but the value of those end-effects can be difficult to determine.

An alternative methodology, which is being used in the IRP, is to utilize a real levelized capital revenue requirement in the analyses. This eliminates the need for an end-effects adjustment, and provides a reasonable approach for comparing the revenue requirement of capital resources against each other and also against market purchase resources.

Although real levelized revenue requirements are appropriate for the IRP economic analysis in comparing resource and market purchase alternatives, real levelized revenue requirements may not fit all analysis situations and would not be suitable for calculating the cost impact to customer rates or for negotiating long-term electricity sale agreements.

Table J.2 Real Levelized Capital Revenue Requirement Calculation Example

Real Levelized Capital Revenue Requirement Calculation Example

	year	Nominal	Real Levelized
	1	$19,386	$12,008
	2	$18,233	$12,309
	3	$16,977	$12,616
	4	$15,872	$12,932
	5	$14,886	$13,255
	6	$13,997	$13,586
	7	$13,170	$13,926
	8	$12,362	$14,274
	9	$11,553	$14,631
	10	$10,745	$14,997
	11	$10,013	$15,372
	12	$9,432	$15,756
	13	$8,928	$16,150
	14	$8,423	$16,554
	15	$7,919	$16,968
Present Value @ 7.5%		$122,612	$122,612

Discount Rate = 7.5%
Inflation Rate = 2.5%
Real Discount Rate = (1+discount rate) / (1+inflation rate) - 1
= (1+ .075) / (1+.025) - 1
= 4.878%

Formula for first year of real levelized revenue requirement
= -Pmt(real discount rate,asset life,PV nominal revenue requirement) x (1+inflation rate)
= -Pmt(.04878,15,122612) x (1.025)
= $12,008

Second and subsequent years' real levelized revenue requirement
= prior year real levelized revenue requirement x (1 + inflation rate)

APPENDIX K – RETAIL LOAD FORECASTING

INTRODUCTION - METHODOLOGY

PacifiCorp estimates load by customer class in each state and then adding losses to the sum of the customer class loads. PacifiCorp uses different approaches in forecasting different customer class sales. PacifiCorp also uses different methods to forecast the growth over different forecast horizons. Near term forecasts rely on statistical time series and regression methodologies while longer term forecasts are dependent on end-use and econometric modeling techniques. These models are driven by state level economic forecasts of employment and income provided by public agencies and commercial econometric forecasting services.[23]

NEAR TERM METHODS

Residential, Commercial, Public Street and Highway Lighting, and Irrigation Customers
Sales to residential, commercial, public street and highway lighting, and irrigation customers are developed by forecasting the number of customers in each class and forecasting the use per customer in each class. The forecast of kWh sales for each customer class is the product of two separate forecasts: number of customers and use per customer.

The forecast of the number of customers relies on weighted exponential smoothing statistical techniques and is based on a twelve-month moving average of the historical number of customers. For each customer class the dependent variable is the twelve-month moving average of customers. The exponential smoothing equation for each case is in the following form:

$$S_t = w*x_t + (1-w) * S_{t-1}$$

$$S_t^{(2)} = S_t *x_t + (1-w) * S_{t-1}^{(2)}$$

$$S_t^{(3)} = S_t^{(2)} *x_t + (1-w) * S_{t-1}^{(3)}$$

where x_t is the twelve-month moving average of customers. The form of this forecasting equation is known as a triple-exponential smoothing forecast model and as can be derived from the equations most of the weight is applied to the more recent historical observations. By applying additional weight to more current data and utilizing exponential smoothing, the transition from actual data to forecast periods is as smooth as possible. This technique also ensures that the December to January change from year to year is reflective of the same linear pattern. These forecasts are produced at the class level for each of the states in which PacifiCorp has retail service territory. PacifiCorp believes that the recent past is most reflective of the near future. Using weights applies greater importance to the recent historical periods than the more distant historical periods and improves the reliability of the final forecast.

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[23] PacifiCorp relies on state level economic forecasts provided by DRI-WEFA; in addition to state office of planning and budgeting sources.

The average use per customer for these classes is done via a regression analysis on the average use per customer to determine if there is any material change in the trend over time. The regression equation is of the form

$KPC_t = a + b*t$

where KPC is killowatthours per customer and "t" is a time trend variable having a value of zero in 1992 and increasing by increments of one thereafter. "a" and "b" are the estimated intercept and slope coefficients, respectively, for the particular customer class. As in the forecast of number of customers, the data is weighted such that more recent historical periods have a greater influence on the forecast than more distant historical periods. The forecasts are reviewed for reasonableness and adjusted if needed. The forecast of the number of customers is multiplied by the forecast of average use per customer to produce annual forecasts of energy sales for each of the four classes of service.

Industrial Sales and Other Sales to Public Authorities

These classes are diverse. In the industrial class, there is no typical customer. Large customers have differing usage patterns and sizes. It is not unusual for the entire class to be strongly influenced by the behavior of one customer or a small group of customers. In order to forecast industrial and other sales to public authorities customer loads, these customers are first classified based on Standard Industrial Classification (SIC) codes, numerical codes that represent different types of businesses. Customers are further separated into large electricity users and smaller electricity users. PacifiCorp's forecasting staff, which consults with PacifiCorp customer account managers assigned to each of the large electricity users, make estimates of that customer's projected energy consumption. The account managers maintain direct contact with large customers and are in the best position to know about their plans or changes in business processes that might impact their energy consumption. In addition, the forecasting staff reviews industry trends and monitors the activities of the customers in SIC code groupings that account for the bulk of the industry sales. Forecasting staff then develops sales forecasts for each SIC code group and aggregates them to produce a forecast for each class.

LONG TERM METHODS

Economic and demographic assumptions are key factors influencing the forecasts of electricity sales. Absent other changes, demand for electricity will parallel other regional and national economic activities. However, several influences can change that parallel relationship, for example changes in the price of electricity, the price and availability of competing fuels, changes in the composition of economic activity, the level of conservation, and the replacement rates for buildings and energy-using appliances. The long term forecast considers all of these as variables. The following is a brief discussion of the methodology implemented for the long term forecast. A more descriptive discussion of the equations and methodology used for the long term forecast can be found in the Load Forecasting Appendix of the Resource and Market Planning Program (RAMPP – 3) dated April 1994.

Economic and Demographic Sector

Employment serves as the major determinant of future trends among the economic and demographic variables used to "drive" the long-term sales forecasting equations. PacifiCorp's methodology assumes that the local economy is comprised of two distinct sectors, "basic" and "non-basic," as presented in "regional export base theory."

The basic sector is comprised of those industries that are involved in the production of goods destined for sales outside the local area and whose market demand is primarily determined at the national level. PacifiCorp calculates our region's share of the employment for these specific industries based on national forecasts of employment for the industries.

The non-basic sector theoretically represents those businesses whose output serves the local market and whose market demand the basic employment and output in the local economy determine.

This simplistic definition of industries as basic or non-basic does not directly confront the problem that much commercial employment (traditionally treated as non-basic) has assumed a more basic nature. This problem is overcome by including other appropriate additional national variables, such as real gross national product in the modeling.

Forecasts of state population are used as forecast drivers. From this forecast a service territory level population forecast is developed and used

Two primary measures of income are used in producing the forecast of total electricity sales. Total personal income is used as a measure of "economic vitality" which impacts energy utilization in the commercial sector. Real per capita income is used as a measure of "purchasing power" which impacts energy choice in the residential sector. PacifiCorp's forecasting system projects total personal income on a service territory basis.

Residential Sector

PacifiCorp's residential end-use forecasting model has been developed to forecast specific uses of electricity in the customer's home. It is a hybrid econometric-end use model. The model explicitly considers factors such as persons per household, fuel prices, per capita income, housing structure types, and other variables that influence residential customer demand for electricity. Residential demand is projected on the basis of 14 end-uses. These uses are space heating, water heat, electric ranges, dishwashers, electric dryers, refrigerators, lighting, air conditioning, freezers, water beds, electric clothes washers, hot tubs, well pumps and residual uses. Air conditioning can be either central, window or evaporative (swamp coolers).

For each end use, PacifiCorp looks first at saturation levels (the number of customers equipped for that end use) and how they may change with demographic and economic changes. PacifiCorp determines how many new households are expected to adopt that end use (penetration level) in the future given the economic and demographic assumptions. In addition, the number of houses that currently have the end use will be removed. Some appliances may be replaced several times before a home is removed. The shorter lifetime of various appliances compared to the lifetime of a home is considered. It is also possible that for a particular appliance more than one exists within a household. For certain appliances, e.g., air conditioning, the saturation rate has been adjusted to account for this occurrence. For other appliances, e.g., lighting, the saturation rate is assumed to be one and the usage per appliance for the average household is adjusted to account for more than one light fixture in the house. In this case the average usage per appliance represents the lighting electrical usage in the average household.

The basic structure of the end-use model is to multiply forecast appliance saturation by the appropriate housing stock that is then multiplied by the annual average electricity use per appliance.

Annual average electricity use per appliance is estimated either by using a conditional demand analysis or based upon generally accepted institutional, industry and engineering standards.

PacifiCorp models three structure types and two age categories because consumption patterns vary with dwelling type and age. New and existing homes are separated into single family, multi-family and mobile home dwelling types.

The models allow PacifiCorp to calculate the number of residential customers separated into new and existing customer categories. The customers are distributed between the various structure types and sizes. End uses are forecast for each house and customer category and these are multiplied by the annual consumption level for each end use. Summing the results gives the total residential sales.

Commercial Sector

The commercial model is a hybrid econometric-end-use model like the residential model. It forecasts electricity in the same fashion but uses energy use per square foot for seven end uses among 12 commercial activities.

The seven end-uses are space heating, water heating, space cooling, ventilation, refrigeration, lighting and miscellaneous uses.

Twelve vertical market segments (building types or commercial activities) are modeled: communications/utilities/transportation, food stores, retail stores, restaurants, wholesale trade, lodging, schools, hospitals, other health services, offices, services, and a miscellaneous category. The 12 vertical market segments (VMS) are defined based upon Standard Industrial Classifications (SIC).

Industrial Sector

Unlike many other electric utilities, PacifiCorp's industrial sector is not dominated by a small number of firms or industries. The heterogeneous mix of customers and industries, combined with their widely divergent electricity consumption characteristics indicates a substantial amount of disaggregation is needed in developing a proper forecasting model for this sector. Accordingly, the industrial sector has been heavily disaggregated within the manufacturing and mining customer segments.

The manufacturing sector is broken down into ten categories based on the Standard Industrial Classification Code System. These are: food processing (SIC 20), lumber and wood products (SIC 24), paper and allied products (SIC 26), chemicals and allied products (SIC 28), petroleum refining (SIC 29), stone, clay and glass (SIC 32), primary metals (SIC 33), electrical machinery (SIC 36) and transportation equipment (SIC 37). A residual manufacturing category composed of all remaining manufacturing SIC codes is also forecast.

The mining industry, located primarily in Wyoming and Utah, has also been subjected to a significant level of disaggregation. Separate forecast are completed for the following industries; coal mining (SIC 12), oil and natural gas exploration, pumping and transportation (SIC 13), non-metallic mineral mining (SIC 14); there also exists an "other" mining category in some states.

The industrial sector is modeled using an econometric forecasting system.

Other Sales

The other sectors to which electricity sales are made are irrigation, street and highway lighting, interdepartmental and "other sales to public authorities."

Electricity sales to these smaller customer categories are either forecast using econometric equations or the sales are held constant at historic levels.

Merging of the Near Term and Long Term Forecasts

The near term forecast has a horizon of at most three years while the long term forecast has a horizon of approximately twenty years. Each forecast uses different methodologies that model influential conditions for that time horizon. In the case where the forecast of usage for a customer class appears to be different for the near term and the long term, judgment and mathematical techniques are implemented in order for the value in the last year of the near term forecast horizon to converge to the long term forecast at some point in the long term forecast horizon.

Allocating Sales Forecasts by Month

The monthly forecast of sales and consumers are developed for each state and customer class from the annual forecasts produced by either the near-term or long-term models by developing an average monthly shape using the most recent five-year history. This process captures any changing trends in usage on a monthly basis. This average monthly shape is then applied proportionately to the annual forecasts to arrive at monthly numbers by class and state.

System Load Forecasts

The sales forecast for each state is increased by estimates of system line losses to create the system load forecast. Line loss percentages represent the additional electricity requirements to move the electricity from the generating plant to each end-use customer.

System Peak Forecasts

The system peaks are the maximum loads required on the system in any 15-minute period. Forecasts of the system peak for each month are prepared based on the load forecast produced using the methodologies described above. The peaks are then forecast for two different times: the maximum usage on the entire system during each month (the coincidental system peak), and the maximum usage within each state during each month.

The coincidental system peak forecast utilizes the forecasted system load data, adjusted by historical coincident factors. The coincident factor is calculated based on the historical peak divided by the average load in each month. The average of the coincident factor for the last five years is calculated and is applied to the forecasted system load to arrive at forecasted coincidental system peaks consistent with the level of the forecasted load.

Hourly Load Forecasts

Once the annual energy levels are produced they are spread to monthly values using historical consumption patterns. These are further distributed to daily and hourly shapes on historical consumption patterns.

Using historical data PacifiCorp establishes average daily and weekly load shapes. The monthly load is then distributed across the weeks and days of the year using these historical shapes. These shapes are based on seven years of historical loads. Different shapes are developed for each of the jurisdictions in which PacifiCorp has load. After the initial distribution there is an adjustment factor used to calibrate the results to the monthly totals and a calibration to make sure the values align with historical load duration curves so the pattern is in keeping with historical usage patterns.

Summary of System Load Forecast

The load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.2% annually. The eastern system continues to grow faster than the western system, with an average annual growth rate of 2.2% and 2.0% respectively over the forecast horizon. There is a change in the growth rates in the east system in the later years of the forecast horizon due to a reduction of loads in Western Wyoming. There are many natural gas fields in Western Wyoming served by the Company. These fields are expected to deplete in the coming years and cease operations. In the base case this occurs after approximately 30 years of gas extraction.

APPENDIX L – RENEWABLES/WIND INTEGRATION

Integrating wind energy into PacifiCorp's power system is expected to incur system costs in excess of that which would be due to an equivalent amount of energy delivered to the system on firm, fixed schedules. Those additional costs need to be estimated in order to understand the relative value of wind energy compared with other resources. The methods developed to estimate those costs are described in this paper, along with the results of applying the methods to PacifiCorp's system.

BACKGROUND

PacifiCorp currently purchases 83 MW of wind energy from wind resources located in Wyoming. In addition, PacifiCorp provides integration services for more than 200 MW of wind power from projects located in Wyoming and along the eastern Oregon/Washington border. PacifiCorp's Integrated Resource Plan portfolios included renewable resources sufficient to meet its potential obligation renewable portfolio standard under consideration by Congress. Wind resources in excess of 1,000 MW of installed capacity may be required to meet that standard. PacifiCorp also evaluated a predominantly renewable energy portfolio for meeting loads that added another 1,420 MW of wind capability to the system. Control area operators raise serious concerns regarding the ability of the power system to accommodate resources that vary as rapidly and unpredictably as wind, especially at these high levels.

Utilities ensure reliability by dynamically responding to imbalances in demand and supply. Resources are scheduled to ramp in generation when loads are increasing, and to reduce generation as loads subside for the day—other resources are made available to respond on a near instantaneous basis. Flexible resources that can change their output over periods of hours and seconds are key to responding to the rapid changes in loads and unexpected changes in resource output (outages and derates). It is expected that additions of wind resources will increase the need for flexible resources to meet reliability standards. One category of flexible resources are operating reserves—resources that are available on short notice to provide additional power as needed.

The Western Electric Coordinating Council (WECC) sets reliability standards for western utilities. WECC describes Operating Reserves as follows:[24]

> *The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to:*
>
> - *Supply requirements for load variations*

[24] WECC Reliability Criteria, August 2002, http://www.wecc.biz/documents/policy/WECC_Reliability_Criteria_802.pdf. p110.

- *Replace generating capacity and energy lost due to forced outages of generation or transmission equipment*
- *Meet on-demand obligations*
- *Replace energy lost due to curtailment of interruptible imports*

Calculating the quantity of reserves has not been an exact science as practiced in the utility industry. Many years of experience with thermal and hydro resources has lead to some industry standards. One such standard is to maintain contingency reserves equal to the sum of 5% of hydro resources and 7% of non-hydro resources operating to meet load on any hour. Clearly this standard does not take into account either the nature of the load, or the characteristics of generating resources. For example, an electrical control area comprised largely of industrial loads may not need the same quantity of operating reserves as a less predictable, largely retail customer load. Due to its complexity, control area operators do not generally undertake a complete analysis of operating reserve requirements.

In addition to needing to assure sufficient flexible resources available to meet demand obligations, PacifiCorp needs to understand the extent to which the system incurs additional costs due to the relatively volatile and less-predictable nature of wind generation. Those costs are termed Imbalance Costs for the purpose of this paper[25].

Because of the implications for reliability and PacifiCorp's role as control area service provider, PacifiCorp undertook to define methods of assessing both incremental reserve requirements, and additional dispatch costs due to integrating wind resources on its system. While it is clear that the methods employed will require future refinements, PacifiCorp feels that they represent a reasonable approximation for estimating wind integration costs given the characteristics of PacifiCorp's control areas until further analysis can be undertaken.

IMBALANCE COSTS

Henwood's PROSYM model was used to estimate the difference in system costs[26] between firm contract delivery at constant rates over time, and an equivalent amount of energy from simulated wind resources. Wind generation fluctuated hourly based on available historical wind data.[27] The alternatives were tested for wind and contracts separately on the west and east sides of PacifiCorp's system. The model was run for three future years at five levels of added wind

[25] Note that the term Imbalance Cost as used in this paper is consistent with the definition commonly found in FERC pro-forma transmission tariffs. FERC tariff imbalance costs are calculated based on the net difference in loads and resources averaged over an operating hour. The determination of Imbalance Cost does not take into account operating or contractual restrictions that may be associated with transfers into or out of any given load and resource area within PacifiCorp's system or potential physical or financial ramifications under future market structure rules.

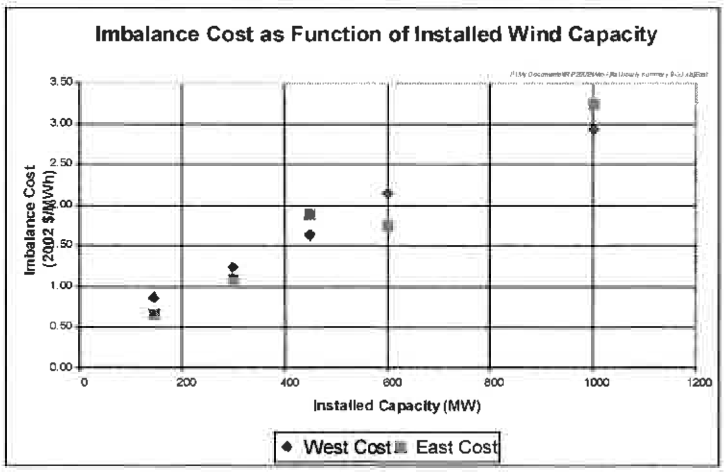
[26] System costs = dispatch costs + market purchase costs – market sales revenues

[27] The hourly wind sites modeled in this study were based on simulated historical hourly generation data from the Stateline and Foote Creek sites. The two data streams were modified by lagging by one hour and moving data ahead one hour to create four new data ranges for the model. The two Stateline streams were added together and then sized to the installed capacity level for the West side site. The two new Foote Creek sites were combined and prorated up to the various installed capacity levels for the East side site.. A single year of hourly generation was repeated for each of the three years of the study.

capacity. The three years did not show a consistent increase or decrease in costs over time. This result was attributed to resource additions in intervening years. For consistency, PacifiCorp averaged the three years to estimate imbalance costs.

The results of the analysis are presented in the chart below. The model showed relatively little difference between the east and west sides of the PacifiCorp system. At wind penetration levels of 1,000 MW PROSYM reports average imbalance costs of about \$3/MWh. This confirms that costs increase with penetration levels. The costs assessed by PROSYM appear to increase roughly linearly with installed capacity at the levels tested in the model.

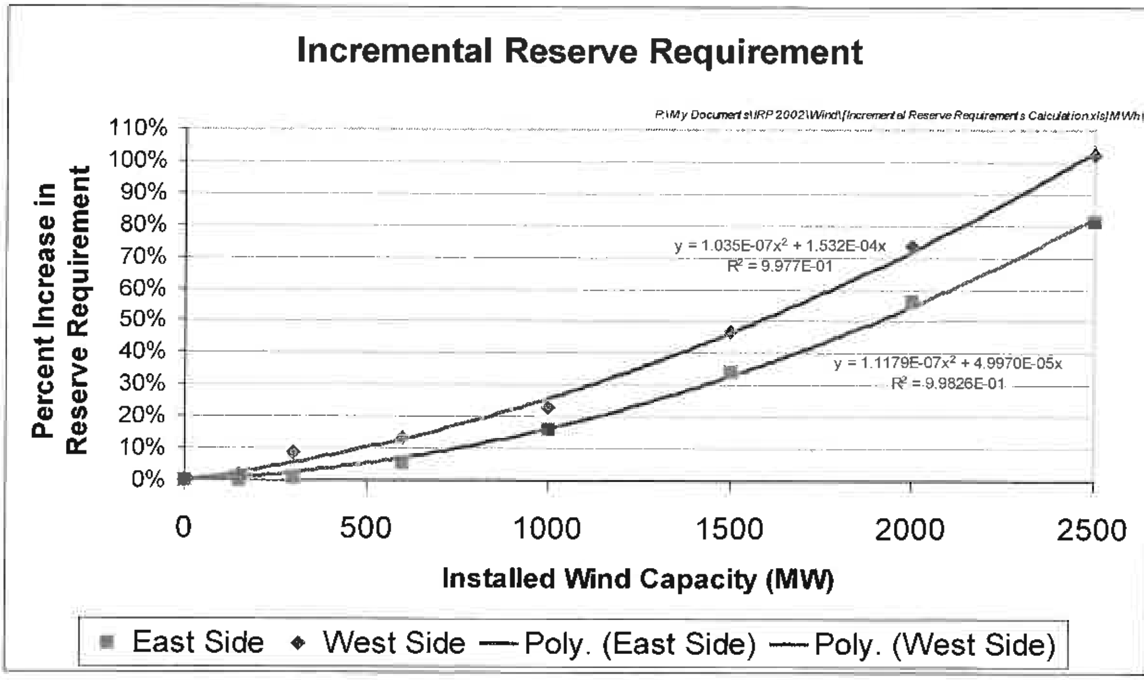
Figure L.1 Wind Imbalance Costs



INCREMENTAL OPERATING RESERVE REQUIREMENTS

Incremental reserve requirements were estimated by comparing the relative dynamic range of loads with and without wind. The standard deviation of hourly loads for a year was calculated. A new standard deviation was computed after subtracting out various levels of wind generation. The fractional difference in standard deviations was taken as an estimate of the increased need for operating reserves. Results are presented in the chart below. Note that the relative increase is larger on the west side for a given wind penetration level. This is due to west side loads being generally lower than on the east side. A given level of wind capability therefore represents a higher fractional penetration on the west side than on the east. In the range of wind capability levels examined, the incremental reserve requirement can reasonably be described by a quadratic polynomial.

Figure L.2 Wind Incremental Reserve Requirement



Assuming that the fractional increase in standard deviation of hourly loads with and without wind is proportional to the increased need for reserves, the incremental need for reserves can be estimated. Factoring in the cost of reserves results in an estimation of the cost of incremental operating reserves attributable to wind.

Operating reserves are typically held on hydro units when available, and higher variable cost thermal units to the extent they are needed. PacifiCorp holds an existing portfolio of resources that can be arranged from highest variable cost to lowest. Holding reserves on unloaded hydro units, and above-market-cost thermal units incurs relatively little cost. However, as the need for reserves increases, the likelihood of having to carry reserves on economic thermal units and loaded hydro units increases. This means that the costs of holding reserves increases with the level of reserves being held. Costs of holding reserve may increase over time due to increases in overall market prices[28]. Also important is the type of resource additions over time.

The foregoing makes clear that generally, the cost of reserves is not a linear function. However, at incremental levels examined, the relationship between cost of holding reserves and the amount held was nearly linear. As a result, the cost per MWh of wind capacity additions will increase linearly with the added capacity. A formula was developed to express the cost of incremental reserves required and is displayed below:

$$C_w = A\frac{P_w}{f} + B/f$$

[28] The cost of reserves also changes over hours and season. The calculation here assumes an average cost over the year.

Where C_w = incremental reserve requirement Cost (2002 \$/MWh)
P_w = installed wind capacity (MW)
f = average wind capacity factor
A = 5.74E-4 East, 2.46E-4 West
B = 0.243 East, 0.365 West

Example

Locate 500 MW of wind capacity in Utah, with a capacity factor of 35%

The Cost per MWh for incremental reserve requirements would be:
.000574 X 500 / .35 + .243/.35 = 1.51 \$/MWh

For 1,000 MW at an average 30% capacity factor, the cost would be 2.72 \$/MWh.

Similar resources located on the west side would cost \$1.39 and \$2.04 respectively.

Caveats

The foregoing analysis is thought to represent a reasonable approach to estimating costs associated with integrating wind resources into PacifiCorp's power system until further analysis can be performed. Many assumptions have necessarily been made to do this analysis. Some of the main assumptions include:

1. PROSYM ability to accurately reflect imbalance costs
   PROSYM dispatch model logic has complete foreknowledge of wind generation in its unit commitment logic. This probably leads to undercounting some costs associated with unit start-ups. The extent of the error depends to some extent on the ability of forecasters to forecast wind output at least a day in advance. Alternatively, PROSYM assumes a hydro dispatch without consideration of wind generation. This tends to overestimate the imbalance costs, especially on the west side of the system where there is a significant amount of hydro.

2. Operating reserve requirements are proportional to hourly load volatility net wind generation.
   This assumption appears to be reasonable, but has no firm theoretical foundation. In fact, it is not clear whether operating reserves represent a sufficient mechanism for integrating large amounts of wind. For example, it may be necessary to increase system flexibility to decrease generation, not just increase generation as represented by operating reserves. Current practice for reserves was developed from many years of operating experience—experience lacking for large amounts of wind generation. While the analytical framework for the analysis appears reasonable, experience may well suggest more refined and accurate techniques for assessing wind integration costs.

3. Cost of reserves remains relatively constant relative to market prices.

The cost of reserves is dependent on the difference between the variable costs of PacifiCorp's marginal resource and the market price for power. The cost of holding reserves will tend to increase with high market prices, and decrease with lower market prices. Costs calculated in this analysis are based on current projections of market prices and PacifiCorp resource costs and represents a snapshot based on an assumed wind pattern and market price shape. Further stochastic analysis will likely be required in order to determine a range of outcomes. The risk model is not yet able to simulate the stochastic process of wind.

4. Sufficient transmission to fully integrated wind resources with the system.
   Wind resources are often located far from load centers. The analysis here assumes wind resources have strong interconnection with the balance of the system.

5. Intra-hour variability is not significant.
   Experience to date suggests the intra-hour variability of wind generation does not result in a material a cost issue. However, this assumption is based only on the observations of operations and may change if the wind resoucre capacity is vary large or very centralized. A high level of intra-hour variability for a given wind project is likely to result in the need for increased spinning reserves by operators in order to maintain compliance with then-current reliability criteria. In addition, a high level of intra-hour variability could introduce financial imbalance risk in the event future market imbalance rules penalize wind generation in the same fashion as other forms of generation resources.

6. RTO
   Cost calculations are necessarily based on historical practice relative to future price expectations. The RTO, as discussed in Chapter 3, represents a significant future Paradigm Risk. As with any Paradigm Risk, RTO rules and guidelines, when finally implemented, could affect the cost calculations positively or negatively.

TOTAL WIND RESOURCE COSTS

The foregoing analysis considered system costs specific to integrating wind power facilities into PacifiCorp's control area. Total system costs of wind power also include power plant and facility capital costs, operations and maintenance costs, transmission facilities costs, and consideration of the federal production tax credit and valuation of renewable energy credits ("green tags"). PacifiCorp used the following assumptions in arriving at total wind resource costs.

<u>Wind Resource Cost Assumptions</u>

Capital Costs ($2002/kW)	$1000
O&M ($2002/kW)	$22.65
Economic Life	20 years
Transmission Cost ($2002/MWh)	$2-6
Production Tax Credit ($2002/MWh)	($12)
Renewable Energy credit ($2002/MWh)	($2)

Real Discount Rate	4.9%
Capacity Factor	36% East[29], 32% west

The range of transmission costs represents uncertainty regarding specific locations. Ranges are shown for production tax and renewable energy credits. The production tax credit is dependent on periodic congressional approval, and the renewable energy credit dependent on state and federal legislation as well as the emerging market for these credits. These issues suggest considering a range of uncertainty in estimating total wind resource costs. Table L.1 puts the above figures on a per MWh cost basis.

Table L.1 Wind Resource Costs per MWh

	2002 $/MWh	(levelized)
	Low	High
Capital and O&M (20yr life)[30]	$40.00	$50.00
Transmission	$2.00	$6.00
Integration (imbalance and incremental reserves)	$5.00	$6.00
Production Tax Credit ($18.00 1st 10 years)	-$12.00	$0.00
Renewable Energy Credits ($5.00 1st 5 yrs)	-$2.00	$0.00
Total	$33.00	$62.00
Average	$47.50	

The range of costs is a factor of two, depending strongly on the continuation of production tax credits and the marketable value of renewable energy credits, and dependent to a lesser degree on the cost of transmission from favorable wind sites.

SUMMARY

PacifiCorp finds both system balancing costs and incremental operating reserve costs increase as wind capacity is added to the power system. The east and west sides of the system have different costs due to different reserve margin costs and relative sizes of the systems. The incremental Operating Reserve and Imbalance Costs of integrating 1000 MW of wind capacity on either side of PacifiCorp's system would be roughly $5.50/MWh ($3.00 for imbalance costs, $2.50 for incremental reserve requirements).

Total system costs for wind resources were assessed from $31/MWh to $62/MWh. The relatively large range is due in significant part to the uncertainty of government support for the production tax credits, and the marketable value of renewable energy credits. The range is also a

[29] East capacity factors are based on production characteristics from wind plants located in Wyoming. Wind sites located in Utah or other parts of Wyoming may have a lower expected capacity factor.
[30] NWPPC New Resource Characterization for the Fifth Power Plan, August 2002.

product of the site-specific nature of wind costs (capacity factors, transmission costs, and site preparation).

Finally, the above results do not directly address the following issues which require additional analysis:

- Project specific interconnection or other expenses that drive the cost of development above $1,000/kW,
- Contractual or operational limitations associated with PacifiCorp's system that limit the acceptance and transfer of power into or out of a given load/resource area,
- The impact of intra-hour production volatility upon PacifiCorp's spinning reserve requirements,
- Stochastic variation of production and price levels in order to determine a range of imbalance cost impacts,
- Stochastic approach to incremental reserve expenses due to seasonal price and production variations,
- The impact upon market liquidity and prices for an entity known by the rest of the market to have a consistent real-time balancing requirement.

APPENDIX M – GLOSSARY

Ancillary Services: Interconnected Operations Services identified by the Federal Energy Regulatory Commission (Order No. 888 issued April 24, 1996) as necessary to effect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff.

Antithetic Sampling: The meaning of "antithetic" sampling is as follows: In Monte Carlo techniques a (pseudo) random process is used to generate sample values of a distribution to represent a shock to a stochastic variable. In sampling values from a normal distribution with mean 0 and variance 1, the antithetic sampling method pairs up iterations. This method exploits the fact that the distribution is symmetric about the mean. For each random value x selected (in an odd numbered iteration), the value –x is selected in a corresponding (even numbered) iteration. For each Monte Carlo iteration the values selected are used in the calculations of the two-factor lognormal model as described in Appendix H.

The antithetic sampling method speeds up convergence of the sample mean for each of the stochastic variables simulated, and reduces sample variance, which is a measure of the difference of the sample mean from the expected value. Antithetic sampling is a fairly common approach used to increase computational efficiency of Monte Carlo techniques.

Average Demand: The measure of the total energy load placed by customers on a system divided by the time period over which the demands are incurred.

Base Load: The minimum amount of electric power required over a given period of time at a steady rate.

Best Available Control Technology (BACT): Emission controls generally required for new source permitting. The best controls available when considering health, visibility, and economics.

Bonneville Power Administration (BPA): A Federal power marketing agency that markets the power produced by the Federal Columbia River Power System (primarily federally-owned hydrogeneration facilities) within the Pacific Northwest, and operates a vast network of federally-owned transmission facilities.

California-Oregon Border (COB): A trading point on the electric grid in the Northwest.

Call Option: the option buyer has the right but not the obligation to call or buy energy and capacity at specific rates at a defined strike price.

Capacity: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress. For purposes of the IRP the capacity of a generating unit is the maximum load available for dispatch, subject to forced outages, at the discretion of the operator.

Coefficient of Variation: A relative measure of dispersion equal to the standard deviation divided by the mean.

Congestion: refers to transmission paths that are constrained, which means limit power transactions because of insufficient capacity. Congestion can be relieved by increasing generation or by reducing load.

Congestion Costs: Costs that arise from the redispatching of a system due to transmission constraints.

Contingency Reserves: 5% of Control Area Demand carried by Hydrogeneration and 7% of the Control Area Demand carried by the thermal units. See ACE.

Control Area: is a geographical area in which a utility is responsible for balancing generation and load. PacifiCorp system is modeled as two control areas in the IRP.

Combined Heat and Power (CHP): The use of a single prime fuel source such as reciprocating engine or gas turbine to generate both electrical and thermal energy to optimize fuel efficiency. Also known as cogeneration.

Clean Air Act (CAA): Federal legislation enacted to establish standards for the emission levels of various air pollutants. The CAA was last modified in 1990.

Clean Air Initiative (CAI): Internal PacifiCorp program to identify potential new emission control regulations and the cost impact resulting for such new requirements.

Clear Power Act (CPA): is a more stringent proposed legislation, with lower annual emission caps for SO2 and mercury than CSA, and an emission cap for CO2.

Clear Power Act (Jeffords Bill or CPA): is a more stringent proposed legislation, with lower annual emission caps for SO2, NOx, and mercury than CSI, and an emission cap for CO2.

Clear Skies Initiative (CSI): Proposed legislation sponsored by the Bush Administration which reduces emission levels for SO2, NOx, and Hg from the current CAA and would establish cap and trade systems for NOx and Hg. Does not include an emission cap for CO2.

Combined-cycle Combustion Turbine (CCCT): A electrical generation device powered by fossil fuel (natural gas), that combines a combustion turbine with a steam turbine to produce electrical generation.

DOE: United States Department of Energy.

DSM Decrement: Since DSM reduces loads, the effect of increasing DSM is called the DSM decrement.

Decrement Value: The expected value associated with a DSM program. The decrement value for a given year is determined by subtracting the revenue requirement of a portfolio which includes a given DSM program and from the revenue requirement of the same portfolio without the DSM program.

Demand: The amount of electric power required at any specific point or points on a system. The requirement originates at the energy consuming equipment of the consumers.

Demand Forecast: An estimate of the level of energy or capacity that is likely to be needed at some time in the future.

Demand-side Management (DSM): Methods of managing electrical resources that affect use, rather than generation, of electricity, e.g., energy efficiency or load control measures.

Deterministic Simulation: A technique by which a prediction is calculated repeatedly using randomly selected what-if trials. The results of numerous trials are plotted to represent a frequency distribution of possible outcomes allowing the likelihood of each such outcome to be estimated (see Stochastic Modeling.)

Emissions: relates to chemical compounds released from the burning of fossil fuels, including mercury (Hg); nitrogen oxides (NOx); sulfur dioxide (SO2), and carbon dioxide (CO2).

Energy Information Administration (EIA): An agency of the U.S. DOE that collects and publishes statistics and reports regarding the U.S. energy industry.

Energy Policy Act (EPACT): Federal legislation enacted in 1992 to encourage robust competition in wholesale electricity markets.

Energy Trust of Oregon (ETO): A trust created by Oregon's direct access legislation -- SB1149. The Trust receives funding from a public purpose charge included in retail electric rates, and administers funding of existing and new DSM programs in Oregon for PacifiCorp's and Portland General Electric's customers in Oregon.

Environmental Protection Agency (EPA): A Federal agency that administers Federal environmental policies and legal requirements, including the Clean Air Act and amendments thereto.

Federal Columbia River Power System (FCRPS): The system of generation in the Pacific Northwest (primarily federally owned hydroelectric facilities) operated by the Corps of Engineers and the Bureau of Reclamation, and marketed by BPA.

Federal Energy Regulatory Commission (FERC): The federal regulatory agency responsible for interstate electric power transmission, the sale of electric power for resale and the licensing of hydroelectric plants.

Federal Power Act (FPA): 1935 Federal act establishing guidelines for federal regulation of public utilities engaging in interstate commerce of electricity. Among other things, provides for the re-licensing of hydro projects. See Appendix A.

Firm Power: means power that can be produced from a hydrosystem under adverse water conditions. The amount of firm power a hydro system can produce is determined using Critical Water assumptions

Firm Transmission: means transmission service that may not be interrupted for any reason except during an emergency when continued delivery of power is not possible.

Fiscal Year: April 1 through March 31.

Forward Price: The price per MWh of electricity at a specific trading point during a specific future timeframe.

Fuel Cells: A device that generates direct current electricity by means of an electrochemical process.

Gap: The difference between a load forecast and available resources to meet the load.

Green Tags: A currency used in the energy trade to represent the environmental benefits of renewable electricity generation. Green Tags are also been called tradable renewable energy certificates or renewable energy credits.

Grid: The layout of the electrical transmission system or a synchronized transmission network.

Heavy Load Hours (HLH): This refers to the time of day on a system that would be considered peak demand. Actual hours vary by individual power system. For IRP purposes the heavy load hours are 7 a.m. to 11 p.m., Monday through Saturday (6 X 16.)

Integrated Gasification Combined Cycle (IGCC): Power generation technology that produces electrical power by combusting coal in the absence of sufficient oxygen to produce a low-Btu fuel gas, which is burned in a combined cycle combustion turbine.

Interruptible Demand: The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of system operator, remote tripping, or by action of the customer at the direct request of the system operator.

Light Load Hours (LLH): This refers to the time of day on a system that would be considered off-peak demand. Actual hours vary by individual power system. For IRP purposes, the light load hours are 11 p.m. to 7 a.m., Monday through Saturday, and all of Sunday (6X8 + 24 + Holidays.)

Load Factor: The ratio of average load to peak load during a specific period of time, expressed as a percent. The load factor indicates to what degree energy has been consumed compared to maximum demand or the utilization of units relative to total system capacity, average demand/peak demand.

Load Following: generally means generation responding to changes in load.

Load Management: The management of load patterns in order to better utilize the facilities of the system. Generally, load management attempts to shift load from peak use periods to other periods of the day or year.

Load Profile: Graphical depiction of the quantity of electricity used consumed over a specified time period.

Load Shape: The variation in the magnitude of the power load over a daily, weekly, monthly or annual period.

Long Position: Having more resources than load (see "short position").

Long-term Drift Rate: The meaning of long-term "drift rate" is the measure of the slope or trend in the long-term equilibrium value of a stochastic variable. The drift rate is calculated within the model from the equilibrium values and is not a user-specified parameter.

Maximum Achievable Control Technology (MACT): Emission limitation for new sources means the emission limitation which is not less stringent that the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of deduction in emissions that the permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed major source.

Megawatt (MW): Unit of electric power equal to one thousand of kilowatts.

Megawatt-hour (MWh): A unit of electric energy, which is equivalent to one megawatt of power used for one hour.

Merchant Generators: Non-utility suppliers including co-generators, small power producers, and independent power producers acquiring, developing and owning power plants and marketing their output.

Mid-Columbia: Trading hub for electricity located in central Washington near the mid-Columbia hydro projects.

Multi-State Process (MSP): in April 2002, PacifiCorp and interested parties from across the company's service area initiated an investigation into challenges faced by PacifiCorp as a multi-state utility. The parties entered into a MSP to develop and review possible solutions to those challenges.

National Marine Fisheries Service (NMFS): This Federal agency manages marine commerce, including harvest of Ocean species and is responsible for implementation of the Endangered Species Act when it applies to species that inhabit the Ocean, including anadramous Salmon that populate the Columbia River system. NMFS is significantly involved in the operation of the FCRPS to protect threatened and endangered species.

Nominal Capital Revenue Requirement: Capital revenue requirement calculated by applying traditional ratemaking calculations. Nominal capital revenue requirement is largest when an asset is first placed in service and declines over time as ratebase is depreciated. (See Real Levelized Revenue Requirement)

Nonfirm Transmission: is transmission service that may be interrupted in favor of Firm Transmission schedules or for other reasons.

Non-spinning Reserve: Off-line generating capacity that can be brought on-line within 10 minutes.

North American Electric Reliability Council (NERC): organized to provide coordination in operating and planning a reliable and adequate electricity system.

Northwest Power Planning Council (NWPPC): A federal entity created by Congress as part of the 1980 Northwest Regional Power Planning Act. The intent was to give the citizens of Idaho, Montana, Oregon and Washington a stronger voice in managing the electricity generated at and fish and wildlife affected by the Columbia River Basin hydropower dams.

Notice of Proposed Rulemaking (NOPR): A reference to a proposal issued in draft form by FERC, usually subject to comment and change before promulgated as a regulatory rule.

Off-peak: See LLH.

Operating Margin: The Hourly Operating Margin, after unit forced outage, and is based on WECC Operating Reserves to cover Contingency Reserves and Regulating Reserves.

Open Access Same-time Information System (OASIS): Established by FERC in 1996 via Order 889. Transmission providers are required to separate their wholesale power marketing and transmission operation functions and maintain an electronic bulletin board, or OASIS, to provide information on transmission availability and to make transmission available to the owning utility and others on an equal footing.

Oregon Senate Bill 1149 (SB 1149): The Oregon legislation enacted in Oregon is commonly still referred to by its original Senate bill number: SB1149. This legislation provides for direct market access for commercial and industrial electric customers served by PacifiCorp and Portland General Electric in Oregon. It also requires these two electric utilities to collect from its Oregon retail customers a public purpose charge equal to 3% of revenues to support programs implemented by the Energy Trust of Oregon.

Palo Verde (PV): A trading point on the electric grid located near the Palo Verde nuclear generation facility in southern Arizona.

PIRA: An international consulting firm that also publishes regular reports and markets statistical databases for oil, gas and electric power.

PNW: The Pacific Northwest.

PacifiCorp East: PacifiCorp's eastern control area, covering its power system in Utah, Idaho, Wyoming (excluding the Jim Bridger Plant) and power plants and associated transmission in Arizona and Colorado.

PacifiCorp Power Marketing (PPM): PacifiCorp unregulated marketing affiliate.

PacifiCorp West: PacifiCorp's western control area, covering power system in Oregon, Washington and California, including the output of the Jim Bridger Plant (located in Wyoming) and PacifiCorp's share of Colstrip in Montana.

Paradigm Risks: For purposes of the IRP, Paradigm risks include those risks which cannot be reasonably represented by a number. Similarly, Paradigm risks do not vary according to a known statistical process. Paradigm risks are typically associated with large shifts in market structure or business practices, such as introduction of RTO and SMD.

Planning Margin: The Planning Margin selected is 15% of the annual peak hour when the loads plus long-term firm sales minus long-term firm purchases result in the largest requirement on the system. This target reserve level assumed to provide sufficient future resources to cover forced outages, provide operating reserves regulatory margin, and demand growth uncertainty.

Portfolio: In the context of the IRP, a collection of resource options, existing and new, designed to meet PacifiCorp's expected short position.

Power Marketers: Those who buy and sell electricity as independent intermediaries.

Power Purchase Agreement (PPA): Shaped energy products, usually tied to an asset, that PacifiCorp considers purchases from a credit-worthy market participant.

Present Value of Revenue Requirements (PVRR): The sum of year by year revenue requirements, discounted at an after-tax cost of capital to a common date. The PVRR takes into account the time value of money such that different projections of costs of various timing and magnitude can be evaluated on a comparable basis. (see "WACC")

Profiled Wind: A wind resource modeled with a production shape reasonably representative of the resources expected physical output, e.g. without any associated firming or shaping provided by a third party.

Production Tax Credit (PTC): tax credit available to renewable energy options (see Green Tags.)

Public Utilities Holding Company Act (PUHCA): Federal legislation designed to work in tandem with the FPA (see FPA). PUHCA and FPA of 1935 addresses issues that arose regarding electric holding companies. PUHCA is an act relating to the structure of utilities. It defines what a holding company is, how it is regulated, and limits the kinds of businesses that a holding company can engage in.

Public Utilities Regulatory Policy Act of 1978 (PURPA): Federal legislation to promote independent resource development, including renewable resources and cogeneration, and to reduce utility reliance on imported oil (see Appendix A.)

Put Option: the right but not the obligation to put or sell energy and capacity at specific rates at a defined strike price.

Qualifying Facilities (QF): A designation created by the PURPA act of 1978 for non-utility power producers that meet certain operating, efficiency and fuel use standards set by the FERC.

Real Levelized Revenue Requirement: This is a methodology for converting the nominal year-by-year revenue requirement into a revenue requirement starting value that, when escalated over the same time period, will result in a revenue requirement projection that has the same present value as the nominal year-by-year revenue requirement (see PVRR.)

Regional Transmission Organization (RTO): Pursuant to FERC Order 2000, PacifiCorp is participating with other transmission providers in the formation of a regional transmission organization known as "RTO West."

Regulating Reserves: 175 MW to control frequency to ACE tolerance

Renewable Portfolio Standard (RPS): The proposed RPS requires electricity suppliers to include renewables as a certain percentage of their power generation mix.

Resource and Market Planning Program (RAMPP): previous PacifiCorp IRP study effort.

Restated Transmission Services Agreement (RTSA): Agreement with Idaho Power Company providing, among other things, up to plus or minus 100 MW of Dynamic Overlay Control Service, and bi-directional transfers of 104 MW of power and energy between PacifiCorp's Wyoming System and PacifiCorp's Utah System.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Scenario Risks: In the IRP, Scenario risks include those risks which can be reasonably represented by a number (parameter). However, parameter variability cannot reasonably be explained by a known statistical process. For purposes of evaluation, Scenario risk parameters are manually adjusted (or stressed) to test the impact of their variation upon modeling results. Such testing is typically used to evaluate an abrupt change in risk factors (e.g. changes in carbon taxes).

Shaped-products: PPA agreements, which try to match the purchased energy to PacifiCorp's load requirements.

Short Position: Being obligated to deliver a commodity or instrument, as opposed to owning the commodity or instrument, for example, having fewer resources than load (see "long position").

Short Term Market: Short-term firm purchases and sales covering longer period than next day to next week transactions that are handle in spot market (see Spot Market).

Short-run Mean Reverting Variations: These are variables that deviate and revert to the mean in the short-run. Within the two-factor lognormal model described in Appendix H there is a short-run component and a long-run component. Only the short-run component incorporates a statistically estimated mean reversion parameter that the model utilizes in determining a stochastic variable's value. Stochastic variables will exhibit mean reversion in the short-run when the mean reversion parameter is non-zero.

Skew: A characteristic of a probability distribution which is not symmetric. For example a positively skewed distribution (with respect to PVRR) is characterized by many smaller than expected outcomes and a few extremely higher than expected outcomes. When distributions are positively skewed, the mean is observed to be higher than the median.

Simple-Cycle Combustion Turbine (SCCT): A combustion turbine, fueled with fossil fuel (natural gas) used for the generation of electricity without the recovery of waste heat.

Spot Market: As conventionally defined, the spot market refers to day-ahead and real-time purchases and sales of electricity. .The IRP defines spot market more broadly to include market purchases and sales, outside of existing long-term contracts and pursuant to the model dispatch logic.

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities.

Standard Market Design (SMD): Proposed FERC Legislation, NOPR RM1-12-000, July 2002 suggests that all load serving entities must meet minimum capacity reserve planning margin of 12% or face potential penalties.

Stochastic Data Input Tools: In the stochastic modeling process, the model equations require that various input parameters be specified. Within the IRP document references to "stochastic data input tools" refer to tools used to perform statistical analysis on historical data. These tools assist a modeler in obtaining input parameters through ordinary least squares (OLS) regression techniques. Henwood licenses a spreadsheet tool to accomplish this task. The "stochastic data input tools" are precisely those tools used in the statistical analysis discussed in the section entitled "Stochastic Parameters: Short-Term" of Appendix H.

Stochastic data input tools should not be confused with Monte Carlo random draws. As described in Appendix H, the Monte Carlo random draws are part of the technique that provides the shock to the variable that is characterized by the model equation and its requisite input parameters.

Stochastic Modeling: A statistical method that uses variability in pricing similar to that expected or historically observed, rather than steady trends, to predict outcomes (see Deterministic modeling.)

Stochastic Risk: For purposes of the IRP, Stochastic risks include those risks which can be numerically represented and whose variability can be reasonably represented by a known statistical process. Stochastic risks are typically associated with business as usual variability in underlying parameters, such as variations in power price

Swap: an exchange of cash flows between a seller and the buyer. The seller owns capacity and energy at a fixed price and has exposure if market prices move lower.

System Benefit Charge (SBC): A charge included in utility rates to be used for the benefit of utility customers for certain programs, such as encouraging renewable resources or energy efficiency; in Oregon, collected by investor-owned utilities, and administered by the Energy Trust of Oregon.

Tolling Option: An arrangement whereby a party moves fuel to a power generator and receives kilowatt-hours in return for a pre-established fee.

Transition Benefit: The positive difference between a resource's value, whether determined by administrative valuation or by the sales price in an auction and the sum of that resource's net book value and FASB 109 asset and inventory balance, minus any Pre-ERTA ITC divided by (1-tax rate). Also referred to as "stranded benefit or stranded cost"

U.S. DOE: The Federal Department of Energy, which administers Federal energy policies and programs.

Utah Bubble: The Utah "Bubble" in the IRP context is defined by the cut-plane into Utah. To the south, three lines: Four Corners to Pinto to Huntington 345 kV, Harry Allen to Red Butte to Sigurd 345 kV and Glen Canyon to Sigurd 230 kV. To the north, Path C and Naughton to Monument 230 kV. To the west: Pavant to Gonder 230 kV and Intermountain to Gonder 230 kV. To the east, Upalco to Carbon 138 kV and Bonanza to Mona 345 kV.

Value at Risk (VAR): The worst portfolio loss that can be reasonably expected to happen over a specified horizon under normal market conditions, at a specified confidence level (such as 95% or 99%).

Vertical Market Segments (VMS): Building types or commercial activities defined based on standard industrial classification.

WACC: Weighted average cost of capital. The after-tax WACC of 7.5% was utilized as the discount rate throughout the IRP in calculating present value of revenue requirements (PVRRs).

WECC: Western Electricity Coordinating Council (formerly known as the Western Systems Coordinating Council, or WSCC); an organization that works with its members to assess and enforce compliance with established criteria and policies for ensuring the reliability of the region's electric service.

Western Regional Air Partnership (WRAP): is a multi-stakeholder process led by states, industry, federal land managers, Native American tribes and environmental groups to improve air quality in the west.

Wheeling: has loosely meant one utility transmitting power generated by another utility or generator to a customer of the generating utility.

Wholesale Sales: Energy supplied to other utilities, municipals, Federal and State electric agencies, and power marketers for resale ultimately to customers.

APPENDIX N – STANDARDS AND GUIDELINES

PACIFICORP COMPLIANCE WITH IRP STANDARDS AND GUIDELINES

Background

Least-cost planning (i.e., Integrated Resource Planning) guidelines were first imposed on regulated utilities by State commissions in the 1980s. Their purpose was to require utilities to consider all resource alternatives, including demand-side measures, on an equal comparative footing, when making resource planning decisions to meet growing load obligations. Integrated Resource Planning (IRP) rules were also intended to require utilities to involve regulators and the general public in the planning process prior to making resource decisions, rather than after the fact.

PacifiCorp is required to prepare an IRP in the States where it provides retail service. While the rules among the States vary in substance and style, there is a consistent thread in intent and approach. PacifiCorp is required to file an IRP every two years with the state commissions. The IRP must look at all resource alternatives on a level playing field and propose a near-term action plan that assures adequate supply to meet load obligations at least cost, while taking into account risks and uncertainties. The IRP must be developed in an open, public process and give interested parties a meaningful opportunity to participate in the planning.

This Appendix provides a discussion on how PacifiCorp complies with the various State Commission IRP Standards and Guidelines in the preparation of this IRP. Included at the end of this Appendix is a matrix that provides an overview and comparison of the rules in each State.[31]

General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with the State Commissions. The preparation of the IRP is done in an open public process with close consultation of all interested parties, including Commissioners and Commission staff, customers, and other stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and also serves to inform all parties on the planning issues and approach. The public input process for this IRP, further described in Appendix B, fully complies with the Standards and Guidelines.

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future loads of PacifiCorp customers and the capability of existing resources to meet this load.

To fill any gap between changes in loads and existing resources, the IRP evaluates all available resource options, as is required by State Commission rules. These resource alternatives include

[31] The IRP rules in Wyoming and California are not summarized in the matrix. The Wyoming requirements are discussed in the appendix. PacifiCorp is not required to file a resource plan in California, but IRP issues are addressed in the rate making process.

supply- and demand-side alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapter 5, meets this requirement.

The resource alternatives are evaluated on a consistent and comparable basis. The evaluation of the alternatives include factors including impact to system costs, operations and reliability, and the impacts of numerous risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western electric system. The models allow for a rigorous testing of all the available resource alternatives available to PacifiCorp. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described in Chapters 3, 4, and 6.

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolios of resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as capital requirements vs. risk, and varying levels of reliability. This portfolio analysis and the results and conclusions drawn from the analysis are described in Chapters 7 and 8.

The IRP Action Plan is provided in Chapter 9. Consistent with the Standards and Guidelines, the Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service. The Action Plan also describes PacifiCorp's approach to procurement, and how it will adapt to changing circumstances as the future unfolds and uncertainties are resolved or evolve. Further, the Action Plan considers licensing and permitting activities so that PacifiCorp can take advantage of opportunities and can prevent the premature foreclosure of options. The IRP also provides a progress report that relates the IRP to previously filed plans in Appendix P.

The IRP and this Action Plan are filed with each Commission with a request for prompt acknowledgement.

Idaho

This IRP is submitted to the Idaho PUC as the Resource Management Report on the resource planning status of PacifiCorp. As discussed above, the IRP fully addresses the *Existing Resource Stack, Load Forecast* and *Additional Resource Menu* elements, as required by the Idaho PUC's rules. The IRP also evaluates DSM using a decremental approach, as discussed in Chapter 5 and Appendix G. This approach is consistent with using an avoided cost approach to evaluating DSM as set forth in the Idaho rules.

Oregon

This IRP is submitted to the Oregon PUC in compliance with its rules to perform Least-Cost Planning. As noted in the Oregon rules, this IRP is relevant to subsequent rate-making. When the IRP is acknowledged, it will become a working document for use by parties in a rate case or other proceeding. We seek acknowledgement of the IRP and specific elements of the Action Plan.

The IRP complies with the process and substantive elements of the Oregon Least-Cost Planning rules. This overall compliance is discussed above. The IRP also includes a significant improvement in the evaluation of risks and uncertainties, compared to previous plans. PacifiCorp is strongly in support of recent Commission interest in working together to understand and manage the many risks and uncertainties associated with planning and ensuring resource adequacy.

The Oregon rules expressly require that competitive secrets must be protected. In this IRP process, PacifiCorp has taken this confidentiality requirement very seriously, and has protected certain information that is commercially sensitive, through protective orders or other appropriate measures.

The Oregon rules require the consideration of the role of competitive bidding in planning for and acquiring new resources. PacifiCorp is proposing a Procurement Program subsequent to this IRP as an element of implementing the Action Plan. Competitive bidding will be an important element of this Procurement Program. This is discussed further in Chapter 9.

This IRP is also consistent with the energy policy of the state of Oregon, as expressed in ORS 469.010. In particular, as can be noted in Chapter 9, PacifiCorp is proposing a detailed Action Plan that has strong elements of energy efficiency improvements and development of permanently sustainable (i.e., renewable) resources. There are also no inconsistencies with the regional plan of the Northwest Power Planning Council, which is currently undergoing revision.

Utah

This IRP is submitted to the Utah Public Service Commission in compliance with its Standards and Guidelines for Integrated Resource Planning. The IRP complies with the process and substantive elements of the Utah rules, as is generally discussed above.

The Utah rules state the IRP process should *result in the selection of the* ***optimal*** *set of resources given the expected combination of costs, risk and uncertainty* (emphasis added). During the public involvement discussions, there was concern raised with the change in modeling tools, because with this change, PacifiCorp lost the IRP analytical capability to automatically select among resource options and build an *optimal* portfolio. PacifiCorp agrees that the modeling framework might benefit from portfolio optimization logic, but building that capability into the modeling capability for this IRP was not attainable. PacifiCorp is committed to exploring this modeling refinement in the coming months, as it makes decisions on what analytical tools to adopt for future resource plans.

The Utah rules do not expressly define the word *optimal*. However, the rules do include considerable discussion on the need to weigh alternative resource risks, uncertainties and externalities. The rules further point out that not all important factors, such as externalities, lend themselves easily to quantification and should be treated qualitatively in the plan. The rules also express the importance of including in the plan a discussion of how the Action Plan would adapt to *different resource acquisition paths for different economic circumstance ... as the future unfolds* and *considerations permitting flexibility ... so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.* These elements of the Utah rules reinforce that the IRP cannot produce an *optimal* plan through modeling logic alone. In the selection of the resource strategy, PacifiCorp must take into account qualitative information and professional judgement, as well as quantified analytical results. The need to remain flexible as the future unfolds is equally important because the future will undoubtedly be different from what we forecast in the IRP. For all these reasons, this IRP complies with the Utah Standards and Guidelines, including the requirement to produce an *optimal* plan.

Consistent with the Utah rules, PacifiCorp determination of Avoided Costs will be determined in a manner consistent with the IRP, with the caveat that the costs may be updated if better information may become available.

The Utah rules stress the importance of a strong relationship between PacifiCorp's business plan and its IRP. PacifiCorp agrees. In the past year, PacifiCorp has made significant improvements to its resource planning organization and methods. These measures have strengthened the alignment of PacifiCorp's business planning, regulatory requirements, resource planning, resource procurement and system operations. A Resource Planning function was created and organized in the Commercial and Trading department to ensure integration with PacifiCorp's resource procurement, trading and risk management functions. New models were developed to ensure the IRP uses a robust analytical framework to simulate the integration of new resource alternatives with PacifiCorp's existing generation and transmission assets, to compare their economic and operational performance. The methodology also accounts for the uncertain future by testing resource alternatives against measurable future risks and possible paradigm shifts in the industry.

The Utah rules require an analysis of the role of competitive bidding for resource acquisitions. PacifiCorp is proposing a Procurement Program subsequent to this IRP as an element of implementing the Action Plan. Competitive bidding will be an important element of this procurement. This is discussed further in Chapter 9.

The Utah rules also call for the identification of *who should bear such risk, the ratepayer or the stockholder*. This discussion is included in Chapter 3 of the IRP.

The Utah rules call for *an evaluation of cost-effectiveness of the resource options from the perspectives of the utility and the different classes of customers, and a description of how social concerns might affect cost effectiveness*. This discussion is also included in Chapter 3.

The Utah rules call for an evaluation of the risks associated with various resource options. The IRP includes a significant improvement in the evaluation of risks and uncertainties, compared to previous plans. PacifiCorp is strongly in support of Commission interest in working together to understand and manage the many risks and uncertainties associated with planning and ensuring resource adequacy.

The Utah rules call for a narrative describing how current rate design is consistent with the IRP goals and how changes in rate design might facilitate the IRP objectives. The Company's current retail rates are consistent with many objectives and support the goals of providing reliable and least-cost electric service to our customers. Residential customers have available both time-of day and inverted rates. These rates, under the requirements of cost of service regulation, meet the additional requirements of minimizing bill impacts on customers, while providing both daily and seasonal price signals. Commercial and industrial customers have available both standard demand and energy rates and time of day offerings. These also provide price signals to customers while minimizing bill impacts.

Changes in rate design may facilitate resource planning objectives. In times of resource deficit in particular, more steeply inverted rates may discourage additional consumption. Any changes in rate design, however, will need to be assessed under the additional requirements of customer impacts, simplicity, stability and fairness.

Utah guidelines require PVRR to be expressed in terms of total resource costs. PVRR values provided in the report are based on total *utility* costs. Total resource costs can be found by adding $81,384,458 to all PVRRs provided herein.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning. The IRP complies with the process and substantive elements of the WUTC rules, as is generally discussed above.

During the course of developing this IRP, the WUTC requested that PacifiCorp provide a State-specific resource plan, as well as a system-wide, integrated resource plan. PacifiCorp agrees that the modeling capability to look at State-specific resource plans would be a valuable addition, but building that capability into the modeling capability for this IRP was not attainable. PacifiCorp is committed to developing this capability for future resource plans.

This IRP does evaluate resource needs, alternatives, performance and cost for each control area region of PacifiCorp. While this does not completely meet WUTC's request, the east- and west-side analysis has been portrayed to give as much information as possible. WUTC staff has assured us that providing this level of detail is sufficient compliance for this IRP. Chapters 7 and 8 address these issues.

Wyoming

On October 4, 2001, the Public Service Commission of Wyoming stipulated that PacifiCorp is to file an annual resource planning and transmission report. This IRP is submitted to the Wyoming Commission for its information and in partial compliance with this stipulation. The IRP complies with the resource planning elements of the stipulation, as is generally discussed above. In addition, PacifiCorp will file annually, by March 31, a Resource Report that provides the current status of the IRP process and how it relates to Wyoming, and describes current transmission projects in the state of Wyoming.

#	Topic	Oregon	Utah	Washington	Idaho
1	Source	Order 89-507 *Least-cost Planning for Resource Acquisitions* April 20, 1989	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992	WAC 480-100-251*Least cost planning* May 19, 1987	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989
2	Filing Requirements	Least-cost plans must be filed with the Commission.	An Integrated Resource Plan (IRP) is to be submitted to Commission.	Submit a least cost plan to the Commission. Plan to be developed with consultation of Commission staff, and with public involvement.	Submit "Resource Management Report" (RMR) on planning status. Also file progress reports on conservation and low-income programs
3	Frequency	Plans filed biennially. Interim reports on plan progress also anticipated.	File biennially.	File biennially.	RMP to be filed at least biennially. Conservation reports to be filed annually.
4	Commission response	LCP *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP *acknowledged* if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.

#	Topic	Oregon	Utah	Washington	Idaho
4	Process	The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Competitive secrets must be protected.	Planning process open to the public at all stages. IRP developed in consultation with the Commission, its staff, with ample opportunity for public input.	In consultation with Commission staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required.	Utilities to work with Commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.
5	Focus	20-year plan, with end-effects, and a short-term (2-year) action plan.	20-year plan, with short-term (4-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed.	20-year plan, with short-term (2-year) action plan. The plan describes mix of generating and conservation resources sufficient to meet current and future loads at lowest cost to utility and ratepayers.	20-year plan to meet load obligations at least-cost, with equal consideration to demand-side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.

#	Topic	Oregon	Utah	Washington	Idaho
6	Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis • Uncertainty must be considered • The primary goal must be least cost, consistent with the long-run public interest • The plan must be consistent with Oregon energy policy • External costs must be considered, and quantified where possible. OPUC specifies specific environmental adders. • Identify to what extent the role of competitive bidding in planning for and acquiring new resources will be used • Avoided cost filing required w/in 30 days of acknowledgement	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand-side, supply-side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds • A cost effectiveness methodology • An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders • DSM and supply-side resources evaluated at "Total Resource Cost" rather than utility cost.	The plan shall include: • Range of forecasts of future demand; • Conservation technical assessment; • Assessment of feasible generating technologies, including purchases from other utilities; • A comparative evaluation of all alternatives on a consistent basis • All plans shall also include a progress report that relates the new plan to the previously filed plan.	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options; • Contingencies for upgrading, optioning and acquiring resources at optimum times; • Report on existing resource stack, load forecast and additional resource menu.

APPENDIX O – RESPONSE TO COMMENTS

COMMENTS ON THE DRAFT REPORT AND PACIFICORP'S RESPONSE

The IRP report was distributed in draft form to the public participants in October 2002, and, after public discussion, written comments were requested by November 27, 2002. PacifiCorp received comments from 21 parties. The final report reflects careful consideration of comments received. Additional comments will be considered in future iterations of the resource planning process. This Appendix summarizes the substantive comments submitted by the parties, and offers PacifiCorp's response. A list of the commenting parties is provided.

Optimality and Finality

Several comments critiqued the lack of automated optimization logic as a component of the IRP analysis. UEO states a need to test a wider range of Portfolios to manually iterate to least cost, and suggests another iteration of the draft report prior to finalizing the plan. UCCS also suggests more time is needed to refine the analysis and Action Plan. UCCS also states the failure to use an optimizing logic means that a least cost Portfolio cannot be obtained with certainty. LWF echoes the concern with lack of an optimization tool. The UPSC states that the IRP does not search for the least-cost, or optimum, resource acquisition, and consequently the IRP must carefully explain how the Plan can meet that requirement of the IRP standards and guidelines. The IPUC notes, however, that resource planning is a dynamic, ongoing effort that must be continually pursued, and that the Action Plan must retain some flexibility.

Response: PacifiCorp is committed to exploring improvements to its IRP analytical tools going forward, including adopting a feature to automate the optimization of Portfolios. However, PacifiCorp disagrees that lacking this model feature, the IRP fails to fully comply with the IRP standards and guidelines. A Portfolio can not be found to be optimal by automated model logic alone, but is subject to qualitative and professional judgement and balancing for risks and uncertainties. The "business rules" which underpin the automated optimization logic are key. Stating that the "lack of automated resource addition logic" weakens the results is not necessarily helpful. Appropriate, realistic, pragmatic and computationally feasible business rules are vital. This is no mean task and the present method of qualitative and professional judgement is an adequate surrogate for such business rules at this point. We know this is true from the "flatness" of the PVRR response surface. Clearly we are very near if not at the optimum.

Condensing qualitative and professional judgement into rules and computer logic while simultaneously balancing for risks and uncertainties is far from a straightforward task. For example, since there are multiple constraints and more than one objective function (least cost and lowest risk at a minimum), the optimum will be extremely sensitive to the relative cost of these externalities – deciphering model results when resources are added automatically can be misleading. Additionally, in "real life" the results can be path dependent (for example, you might not add a wind resource until you had sufficient operating reserves in place first).

Any IRP can also only be determined to be optimal based upon the best available information at a point in time. As circumstances evolve and as better information is obtained, the resource plan may very well need to be adjusted. The ongoing improvement in resource planning and the need to maintain a degree of flexibility are reflected in the Action Plan. This IRP is being submitted for acknowledgement by the PUCs, to comport with the biennial-filing requirement under existing rules. However, as part of Action Plan implementation and through ongoing resource planning activity, the plan will likely evolve over time. Compliance with the least cost planning features of the IRP standards and guidelines is further discussed in Appendix N.

Action Plan Specificity

Several parties called for a more specific Action Plan. The WPSC noted the use of soft verbs in the Action Plan, suggesting the Action Plan appeared to be describing another iteration of resource planning. The WPSC called for an Action Plan that identifies the actions that are critical to achieving near-term results or are critical path steps toward a future achievement. The UEO states the Action Plan must be very specific in terms of the type and magnitude of all resources that the Company is committed to acquire, with special attention to near term actions. While the UCCS notes the need to retain flexibility as an element of resource planning, it too criticized the Action Plan as too vague. OOE and RES both call for more clarity and specificity in the planned actions to develop renewables, with OOE suggesting a minimum annual target would be more meaningfully acknowledged by regulators.

Response: PacifiCorp has made a number of revisions to the Action Plan to address this issue. Some decisions are clear, implementable and timely. These have been identified, defined and slated for action. Other decisions have been identified that depend on future events (Clean Air legislation, Renewables legislation, more clarity on state preferences, the developing natural gas to coal price ratio, etc.) and have been scheduled for future analysis and execution. That is only prudent and it would be pretentious to assume we know the future with respect to items such as these. The Action Plan strives to strike a balance between the need for specifics, particularly on near term or critical path activities, with the need to retain flexibility to adopt to changing circumstances.

Action Plan Must Follow Analytics

Many parties pointed to the possible disconnect between the analytical results and the Action Plan. The UDPU states the Action Plan must be clearly tied to the analytics, and asks for a better explanation of the decision criteria for the proposed direction regarding Portfolio choice. It notes the decision criteria are not clearly developed in the draft IRP. The UCCS notes the Portfolio chosen in the Action Plan ranked third in performance, based on PVRR, and questions whether a customer perspective drove the decision to adopt it. The UEO states that the Action Plan must follow clearly and logically from the various types of quantitative and qualitative analyses, in a way that participants can understand and agree make sense, even if not all parties agree with all aspects of the judgments made.

Response: As discussed in the Final Report, a number of revisions to the Portfolio analysis have been adopted. The Action Plan is now designed based upon the best performing, least cost Portfolio from the perspective of the customers. The Action Plan is also revised, as discussed above. PacifiCorp hope these changes address the concern that the linkage between the analytics and the Action Plan is clear and logical.

Procurement and RFPs

The USM asserts that the IRP seems slanted to direct the development of resources that will provide rate base to PacifiCorp, and calls for consideration of the potential of development with other utilities and expansion of non-PacifiCorp developments. UAE states the IRP does not take into sufficient account the potential for projects owned by other utilities, independent power producers or end-use consumers. DPEC comments focus on the potential for it to provide supply through its long-term excess power supply, or through expansion of its facilities or others. UAE comments that an indispensable prerequisite to any future plant construction, acquisition or repowering is an effective RFP process.

Response: PacifiCorp's IRP is not intended in any way to be slanted toward build, toward buy or toward a specific fuel source. No decision is being made in this IRP to build any specific resources, and it is clearly stated that no preference is predetermined between asset ownership options versus power purchase contracts. The IRP has determined the need for resources with considerable specificity, and identified the desirable Portfolio and timing for procurement. As the Action Plan is implemented, subsequent decisions will be made on a case-by-case basis between competing resource options. These options will be fully developed using a robust Procurement Program, including an effective RFP process. A discussion of the intended Procurement Program is included in the Action Plan of the IRP.

Multi-State Process

The UCCS stated that the results of the MSP should not be a factor in the IRP, because PacifiCorp is required to produce a least cost plan regardless of what results from the MSP. USM echoed this perspective, stating the MSP may direct who would develop additional resources but should not inform what the least cost development direction should be. USM also commented the discussion of MSP creates appearance problems.

On the other hand, the UDPU states the Action Plan should clearly describe the link between MSP and IRP, and calls for a detailed explanation of the risk of failure of the MSP process to reach a favorable conclusion. This could include a MSP timeline and discussion of potential impacts of the process on IRP decisions or implementation of the Action Plan. WPSC also calls for elaboration of the linkage between IRP and MSP, and how short term action planning will proceed with and without MSP clarity. The UDPU further comments that the IRP should provide direction and clarity to the MSP process.

Response: PacifiCorp agrees with commenters that the two processes serve distinct, different purposes, and for this very reason the two processes have been organized and operated separately. At the same time, the Final IRP report continues to point out the clear interdependencies of the IRP and MSP. Any successful IRP effort must satisfy system-wide needs and constraints, must be acceptable to individual states and key parties, and must be financable. In development of the Action Plan, the presumption is that a favorable (i.e., acceptable to all parties) MSP outcome will occur. Failing this, many items in the Action Plan would be revisited. That said, the fundamental need for additional resources identified in the IRP is unlikely to change significantly due to any MSP outcome.

System-wide Planning

The UDPU states its expectation that PacifiCorp will continue to be operated on an integrated system basis and that resource planning should be consistent with this assertion. It asks for a clarification on this question.

Response: The IRP is developed as a system-wide, integrated resource plan. PacifiCorp's expectations for resource planning and operations are consistent with the UDPU stated expectation.

Renewable Resources

There were many comments on the analysis of renewable resources in the Draft IRP. Several commenters were supportive of the attention being given to this resource alternative. RES was supportive of the results and suggested sources for wind integration studies that could further inform the IRP. The UCEA noted the Renewables Portfolio was shown to be the best overall. NRDC also stated the Renewables Portfolio was both least cost and least risk. SCUC advocates adoption of the Renewables Portfolio. LWF comments that the draft fails to justify adopting the Renewables Portfolio. RNP called the draft IRP a sophisticated approach to resource planning and a significant step forward for renewables. RNP also noted the RPS is a prudent consideration, but not the reason alone to justify inclusion of renewable resources in the chosen Portfolio. NRDC and LWF both echoed the view that the RPS should not be the exclusive emphasis for including renewables in the portfolios. RNP and NRDC both propose a more aggressive "front loading" of renewables in implementing the Action Plan. The UEO noted there are many uncertainties surrounding the implementation of large amounts of wind power called for in the Renewable Portfolio, but asserts the IRP analysis does not provide a sufficient basis for not basing the Action Plan directly on the Renewable Portfolio. SLC calls for aggressive pursuit of program options to improve the understanding of renewable resources and reduce the risks associated with full implementation of the Renewable Portfolio.

The IPUC is skeptical about the level of renewables and its cost effectiveness. Despite the Renewables Portfolio's apparent superiority, the IPUC calls for a reality check on what can realistically be achieved in developing renewables. UAE also stated the Renewables Portfolio cannot credibly be projected to be least cost. The IPUC also stated the assumed federal RPS is presumptuous and a No-RPS stress test must be shown. The UPSC also asks for additional stress tests comparing the results of the Portfolios when both the RPS assumption and the CO2 tax assumptions are removed. The UCCS also endorses further analysis of the potential costs and risks of renewables if a RPS is not passed of if the capacity cannot be economically or completely obtained. The UDPU also questioned the level of Renewable investment embodied in all the Portfolios to comport with a RPS level, and called for a justification of this level of renewables in all Portfolios. The UDPU also noted an apparent inconsistency with the Renewables Portfolio being lowest cost, given the study results showing a substantial system savings if the RPS were abandoned. The IPUC also notes the impact of RTOs on the construction and availability of transmission for wind projects should be addressed.

Several assumptions were called into question. RES and NRDC both state the Green Tag assumption was too conservative (assuming a RPS is adopted), while the IPUC stated it was probably too optimistic. The UCCS and NRDC both noted no capacity credit was given to renewable resources, understating the benefits of renewable additions. The WPSC noted a RPS would lead to technology improvements and economies of scale, and the IRP should explicitly state that this has not been factored into the analysis. The WPSC questioned whether the risks associated with renewables were being adequately considered. The IPUC questions the flat wind integration assumption, pointing out a supply curve approach would better approximate the expectation that wind integration costs would likely increase with the size of the resource procured. The IPUC also noted the fuel cell assumption in the Renewable Portfolio appears overly optimistic.

The UCCS calls for further examination and modeling of renewables. RES suggested discussion of the pros and cons between owning or contracting for wind would be helpful. The UDPU suggests an incremental analysis of renewables, rather than the with- and without-RPS analytical approach that was undertaken.

Response: PacifiCorp appreciates all the contributions of the parties as it has endeavored to develop a more robust understanding of the opportunities to develop renewable resources as an element of its portfolio. The proper analysis of renewables is highly quantitative and PacifiCorp believes that we have done this properly and fairly. The Final IRP report reflects a number of changes to the analysis of renewables, which are discussed at length in that document. PacifiCorp is evaluating renewables consistently with other resource options in the Final IRP. Renewables continue to play a very important role in PacifiCorp's resource development plans, as reflected in the Action Plan.

Geothermal Resources

The IPUC stated the solicitation for Renewables should not be limited to wind, but should pursue geothermal opportunities too, suggesting the Raft River geothermal site in Idaho should be considered as one alternative. USM also noted significant cogeneration potential exists that appears to be ignored in the Draft IRP. SCUC also noted cogeneration (i.e., CHP) can be viewed as an important energy saving program to be considered in an IRP. UAE also asserts cogeneration was given insufficient attention in the IRP. On the other hand, WDO comments that from the perspective of geothermal power development, the new IRP is distinctly encouraging for moving to increase power production at the Blundell Plant in southwest Utah, as well as stating intentions to gain new increments of geothermal power going forward.

Response: PacifiCorp agrees that geothermal resources can be clean, reliable and cost effective, and will continue to pursue opportunities to procure this resource as part of its ongoing activity to implement the Action Plan.

DSM Resources

The UDPU stated that DSM evaluation has been greatly improved in the current IRP. IDPU and LWF state their support for the decremental approach to evaluating future DSM levels. UDPU suggests it be updated regularly as actual programs are developed. SEEP also comments that the decremental approach, with details to be determined later, is reasonable provided there is appropriate follow-up. Others called for further analysis of DSM. The UCCS suggested a cost comparison of the historical DSM programs to evaluate for cost effectiveness in light of the new programs being proposed. The UDPU also suggested using cost effectiveness of current DSM programs as a benchmark against future activities. The UEO states that the DSM analysis, and its precise contribution to the Action Plan, needs to be finalized before the IRP is finalized. The UEO suggests a cumulative DSM amount of 600 MW (peak) by 2008 is achievable and cost effective. NRDC believes the DSM target understates the opportunities and urges a complete system-wide assessment of DSM potential as soon as possible and a commitment to prompt midcourse adjustments in the Action Plan based upon the results. SCUC also calls for a more aggressive approach, including possible legislative changes. LWF also calls for more definitive commitments to DSM in the Action Plan. Some existing programs are only planned to operate for one to three years, and SEEP recommends all programs now underway should be continued through 2012 in the IRP.

The UDPU commented that the transmission and distribution avoided cost associated with DSM should be calculated and are important to identifying program cost effectiveness. SEEP calls exclusion of avoided distribution investment as a benefit of DSM a significant flaw that should be corrected. The UEO proposes a value of $0.015/kWh saved for avoided distribution and transmission costs. UCCS also noted the DSM benefit is understated because no capacity credit is given to low capacity factor DSM programs.

The UAE comments that the IRP pays insufficient attention to demand reduction as potential DSM alternatives. It suggests many larger customers may desire an opt-out provision, as an alternative to facing the costs of new resource development. Interruptible tariffs are also suggested as an IRP option that was ignored. The UAE states the IRP should consider such options and analyze the likely impacts. USM also states potential DSM from the industrial sector is omitted, suggesting some industrial operations have the capability to work within class 1 DSM options. The OOE also advocates an examination of real time pricing and critical peak pricing as additional demand response programs to consider.

The UDPU raises the concern that underlying DSM assumptions are not fully articulated in the IRP document, and calls for additional information regarding ramp-up assumptions for each program and the basis for the design of the programs. UDPU also states that more detail from the DSM/EE Task Force should be clearly identified in the report.

SEEP suggests it would be appropriate and correct to make estimates of the energy savings and peak load reductions from non-utility programs, such as the Northwest Energy Efficiency Alliance and the Energy Trust of Oregon. The UDPU notes that PacifiCorp is cooperating with the ETO as the responsibility and funding for these programs is transferred. It suggests this transition should be addressed in the IRP.

The WPUC asks whether the DSM target is too ambitious and whether the risk of DSM under delivery been adequately considered.

Response: As with Renewables, the proper analysis of DSM is highly quantitative and PacifiCorp believes that we have done this properly and fairly. Specific actions have been included in the action plan that address concerns regarding DSM RFPs, quantification of the realistic DSM market, and new program design and initiation. Specific evaluation of potential transmission and distribution deferral benefits is not included in this IRP. These types of benefits are geographically specific, based on the local transmission and distribution system growth rate and the local concentrated effects of DSM programs. PacifiCorp is not applying a general, system-wide transmission and distribution saving. Specific investment needs must be identified for deferral just as this IRP identified specific generation investment that the DSM decrements could defer if implemented. As specific programs are designed, local transmission and distribution benefits will be considered if they can result is the deferral of identified transmission and distribution investment.

Supply-Side Resources

The UPSC requests that tables in the report summarizing supply-side resources be expanded to include all items presented in previous RAMPP studies, and include formulas for derivation of each column displayed. A better explanation of the lead-time required for baseload gas resources is also requested by the UPSC. UPSC and IPUC both also look for more detailed descriptions of each of the Portfolios. The IPUC also notes that gas fired reciprocating engines are not included as a potential supply-side resource.

Response: The tables summarizing supply-side resources has been expanded and is located in Appendix C.

Solar Resources

SLC, LWF, and SCUC all call for serious consideration programs to support solar photovoltaic development, calling particular interest in a rooftop pilot program in the Salt Lake City area.

Response: A solar photovoltaic resource program will be considered as part of the new program designs to fill the planning decrements as outlined in the action plan.

Coal

A number of parties expressed concern with possible development of new coal plant. RNP comments that it does not support including a coal plant as a possible Action Plan item, calling it extremely risky and shortsighted, especially in light of the heavy reliance on coal in the existing resource base. This comment was echoed by NRDC, SCUC, and LWF. The OOE questions the need to option Hunter 4 at this time, reasoning that this was a decision that could be deferred until the next IRP.

OOE notes that Integrated Gasification Combination Cycle (IGCC) technology has lower emissions of criteria air pollutants and to the extent coal is considered, stronger consideration of IGCC should be included. NRDC commented that the discussion in the draft IRP on IGCC is out of date and does not justify leaving this technology out of the analysis. LWF also noted IGCC has significant environmental advantages over pulverized coal.

The UCCS comments that the analysis of Eastern (i.e., Wyoming) coal and transmission upgrades is inadequate.

Response: PacifiCorp is committed to exploring all options that may lead to providing least cost resources for the future. Because of low fuel cost, coal-fired generation historically has been a least-cost generation option. Increasing emphasis on the long-term impacts of the impacts of atmospheric emissions are casting doubt on the viability of a heavy dependence on coal-fired generation for a significant portion of new resources and even continued reliance on coal-fired generation for existing electricity supply. To the extent that these environmental influences enter decision-making gradually, the abundance of the coal resource suggest that coal-fired generation will be among the low cost options in the future. The least cost option is dependent upon the impact of a number of such Paradigm risks including CAI, RTO, MSP and global warming. CAI and global warming specifically impact the low cost fuel choice for thermal resources. The IRP base case assumptions currently contemplate CAI and global warming outcomes that suggest coal may continue to be part of the United States fueling strategy. Coal-fired generation may be particularly advantageous for utilities acquiring resources in the Rocky Mountains because coal is an abundant indigenous resource. For example, Utah and Wyoming have significant coal resources that could be used for fueling new mine-mouthed power plants. Such plants have proven to be some of the most economic base-loaded power producers in the country. These plants are consistently dispatched before most other generation options with the exception of run of the river hydro and nuclear facilities. For example, dispatch costs (fuel and variable O&M) for the proposed Hunter 4 unit run less than $8/MWhr while a gas-fired combined-cycle plant (the most efficient gas plant) will dispatch at about $24/MWhr, based on $3.00/million Btu gas.

Hunter 4 was specifically mentioned in the portfolios and in the IRP Action Plan. Work done to date indicates that this plant, if built, would be one of the more efficient and low cost new generation facilities in the western US, even under most carbon assumptions. If built, the proposed Hunter 4 unit would be constructed with Best Available Control Technology (BACT) equipment and the Hunter Station as a whole, including a new Hunter 4 unit, would emit less SO_2 and NOx than the three-unit plant currently does.

PacifiCorp understands the risks and the benefits associated with coal plant operation. The Company recognizes that from time to time operational problems do occur in coal plants, but this is true of gas-fired combustion turbine facilities and wind farms as well. In addition, coal plant operational risks compare very favorably to market purchase and credit risk exposure and particularly well to gas volatility risk exposure. If base case environmental assumptions change due to factors such as federal legislation, state specific legislation, differing relative fuel economics or technologic shifts, clearly the economic viability of coal-fired generation may change.

PacifiCorp believes it has adequately addressed the risks of future carbon constraints, based on our current understanding of these risks, by adding a carbon value to plant production in the base case portfolio analysis and by running sensitivities on this parameter. Even with such carbon values, coal plants remain a low-cost option.

In summary, it would be imprudent for PacifiCorp to omit coal as one of the least-cost alternatives for further work in the IRP Action Plan.

IGCC as a Coal Plant Option

PacifiCorp has investigated and studied coal gasification since the early 1980's. The Company has been a member of the Utility Coal Gasification Association, now the Gasification Users

Association (UGA), since the early 1980's as well and has been on the UGA board for the last six years. PacifiCorp has had the opportunity to visit all the major gasification demonstrations in this country and some overseas. Through gasification meetings, including the recent Coal Gasification Conference held in October 2002, PacifiCorp has kept informed of the current status and limitations of this technology. Based on numerous contacts, knowledge and experience, PacifiCorp believes that Integrated Gasification Combined Cycle (IGCC) coal technology is not yet ready for full-scale commercial application. Furthermore, many others in the industry share this conclusion.

However, PacifiCorp also believes that reliable, full-scale, commercial gasification will be achieved as both US and overseas IGCC plants gain more experience and establish improved and sustainable capacity factors. Average capacity factors to date have been around 75%. PacifiCorp recognizes that IGCC vendors are willing to guarantee capacity factors of 85% or more - but only with the addition of expensive spare gasifiers and associated equipment. PacifiCorp believes that the higher capacity factors with single-train equipment will be achieved over the next few years but until that has been proven, the Company will not be ready to commit to an IGCC facility. Permitting, design and construction of such a plant will require about five years. Adding these two time periods together puts IGCC beyond the 2010 to 2012 time frame.

PacifiCorp believes that two technical issues with respect to IGCC should also be understood. First, siting an IGCC plant in Utah or Wyoming near the coal resources (at plant elevations of 4500 feet or more) will result in combustion turbine de-ratings that will effectively increase plant production costs by as much as 15% to 20%. Second, SO_2 and NOx emission levels are essentially the same for IGCC and new coal plants with BACT as shown by the demonstration plants being operated today. CO_2 emissions are about 9% better for IGCC than for conventional coal. IGCC technology provides an opportunity to remove CO2 from the flue gas for potential deep-well sequestration. This technique adds additional geographic constraints to siting an IGCC facility and would add dramatically to operating costs.

In conclusion, PacifiCorp believes that IGCC is a promising new technology but that it is not fully proven as a commercial technology. The Company does keep current with ongoing IGCC technology and experience. As this technology matures, as better reliability is proven and as emission improvements are made and demonstrated, IGCC will be considered in the least-cost planning of the IRP.

Eastern Coal

PacifiCorp's early screening of Portfolio options ruled out Eastern coal as a practical option due to the high cost of integrating the resource with new transmission. It is possible that an aggressive RTO future could provide sufficient transmission to reverse this conclusion, but according to the present analysis, such costs would need to be socialized over a large base than just PacifiCorp customers.

Airshed Issues

The WCAC is concerned that inadequate weight was given to concerns about current and potential non-attainment status for PM10, PM2.5 and Ozone along the Wasatch Front. Installing new electrical generation in the urban airshed is especially problematic, WCAC states, because the times of unusually poor air quality are also times of peak power usage.

Response: PacifiCorp is acutely aware of the air quality issues along the Wasatch Front. PacifiCorp recognizes that improving air quality is a critical issue if any new resource is to be built along the Wasatch Front, assuming that is determined to be the most prudent and cost effective decision.

Any new generation facilities built within the non-attainment areas along the Wasatch Front will be equipped and operated to meet the Lowest Achievable Emissions Rate (LAER). As a result, the emissions control equipment must meet the most stringent emissions limitation achievable from such a category or source. In addition to the need to meet LAER constraints, will be the need to provide "offsets" for mitigation. In other words, the addition of the new resource must effectively cause a net reduction in air emissions. To the extent practicable and achievable, PacifiCorp will utilize emissions offsets derived from both actual and recent emissions reductions obtained from other generating assets or process industries. PacifiCorp expects that the decision to proceed with a new Wasatch Front resource will be accompanied by retirement of all or part of the existing Gadsby steam generating units or some other older, less efficient resource. The development of new generating resources along the Wasatch Front, accompanied by the concurrent retirement of the Gadsby, or other generating facilities, will not only result in an improvement in the airshed, it will also result in development of more efficient generation facilities, reduced transmission losses, and decreased water consumption.

Climate Change

SCUC, LWF, NRDC, SLC, and OOE all raised concern that the risk of climate change is urgent and serious, and not adequately considered in the draft IRP.

Response: There is substantial uncertainty regarding the shape and timing of any future requirements on emissions of carbon dioxide (CO2) and other greenhouse gases. While CO2 caps or other requirements are proposed in several multipollutant bills, there is no clear evidence that carbon restrictions are imminent in the US. Even in the midst of this uncertainty, PacifiCorp has chosen to include "carbon adders" as part of the IRP analysis. The range of carbon values serve as a surrogate for the variety of CO2 emissions constraints that could be imposed on the company in the future. It is the company's view that risks to the company and to our customers of future carbon constraints are too great to ignore and it is for this reason that we have explicitly included them in the IRP planning effort.

Transmission

Comments on transmission analysis included the following. The UCCS states that the Transmission Portfolio was not adequately analyzed. In order for a fair analysis to occur, benefits such as wheeling revenues must be included as well as costs. The UCCS also argues that modeling only firm transmission, rather than how the system is operated, contributes to the east side/west side planning, rather than integrated system-wide planning. UCCS seems to suggest some level of non-firm transmission could be relied upon in planning to meet firm loads. The IPUC also commented that the assumption that new transmission would be built without participation by third parties seems unrealistic. The UDPU states it is unclear why more transmission constraints emerge on the East side of the system as opposed to the West.

Response: The IRP analysis modeled PacifiCorp's firm transmission rights, plus the 500MW each for west and east of non-firm spot market purchases/sales. The non-firm assumption is deemed appropriate based on actual operating experience. Wheeling rates were applied to non-firm transmission usage for both purchases and sales. Modeling non-firm between control areas deemed unpractical, as long-term availability is unclear/unreliable. The IPUC comment necessitating 3rd parties involvement is noted, and is consistent with RTO principals.

<u>**Risk Analysis**</u>

The WPSC commented that the Western power crisis is unlikely to be repeated and therefore insufficient reason to be overly cautious in risk analysis. UAE also expressed concern that the IRP generally places undue emphasis on avoiding risk. While consideration of risk is a very important factor, it states avoidance of risk comes at a very high price and may be detrimental to customers and the public interest.

Several noted the risk of relying on merchant plant development is unstated. The IPUC suggests risks associated with purchases from developers of merchant plants should be addressed. The UDPU notes that risk analysis only applies to the build option, and a comparative risk analysis should be performed on the buy option. DPEC also comments that the IRP fails to acknowledge the risks associated with dealing with merchant developers. OPUC suggested that hedging be discussed as a risk management tool. The IPUC opines that a discussion of whether capital intensiveness of some Portfolios is a risk in itself, and assessing this in the tradeoff between capital and risk a factor. OOE raises concern with the conclusion that the risk analysis showed a preference for the Coal/Gas portfolio compared with the Gas/Coal options. RES also questioned whether risk analysis justified not electing the Renewables Portfolio as the preferred option.

The UPSC comments note the risk discussion is arcane, and called for an effort to translate it into lay terms or provide a glossary of technical terms. The UDPU also noted confusion is caused by the inconsistent usage of terms, and in particular the terms risk and uncertainty. UCCS and NRDC both raised concern with comparing the 5th and 95th percentile and to consider using other metric to compare risk between Portfolios from the customers' perspective. The UDPU suggests a discussion on the methods and products to mitigate price volatility is warranted in the IRP.

Response: PacifiCorp will continue to evaluate risks and uncertainties as a central element of its resource planning, and notes it is an element in the Standards and Guidelines in many PacifiCorp jurisdictions. Judgements such as "the Western power crisis is unlikely to be repeated" are proscriptive and do not belong in analysis that includes stochastic estimates of future price paths. The IRP resource strategy and Action Plan have not been overly influenced by this risk analysis, however. As is noted in the Final report, the quantified risk analysis was not a large factor in evaluating among Portfolios. Unquantified paradigm risks may play a more important role as the future unfolds during the course of implementing the Action Plan. PacifiCorp will strive to make the discussion of risk analysis less arcane and user-friendly and we believe improvements have been made in the filed IRP document.

As is discussed in the report, the declining merchant sector is an important consideration. As the Action Plan is implemented, the risks of merchant counterparties will be evaluated on a project by project basis. Such analysis is an important component of the build vs. buy decision process discussed in the plan.

PacifiCorp has and will continue using hedging risk management tools as the Action Plan is implemented. A discussion of the hedging strategy is provided in Chapters 2 and 9.

Planning Margin

The UDPU notes the 15% planning margin is simply based on potential SMD outcomes. Given the importance of the assumption, it suggests PacifiCorp perform a loss of load probability study to determine an optimal planning margin. The IPUC noted the need for more clarity on how the 15% planning margin relates (or does not relate) to the hourly operating margin. The UEO comments that the Action Plan should clearly state exactly what value for the planning margin will be maintained, pending SMD or other changes.

Response: The planning margin used throughout the IRP process has been 15% (with the exception of the "10%" stress cases) and was based on potential SMD outcomes. The planning margin is created for long term planning purposes. The calculation for the long term planning margin takes into account the need for an hourly operating margin. In the modeling dispatch a 7% operating reserve is held to cover the thermal plants on the system and a 5% operating reserve is held to cover the hydro plants on the system.

PacifiCorp will continue to assess the magnitude of planning margin required to ensure safe, reliable, low cost energy for the customer. Part of this assessment will include loss of load probability studies. The risk analysis completed in the IRP does test the performance of the portfolio under varying load levels to ensure the portfolio can meet the requirements.

The need for assessing the planning margin has been included as an action item in the Action Plan.

Spot Purchases

The UCCS views the decision to limit market exposure to 5% of total hours as arbitrary and considers it to be a regulatory risk management tool. It recommends additional analysis of the 5% criterion. The IPUC also questioned the 5% or less assumption and asks how capping spot market purchases at 500 MW may compare to historical practice. UAE also seriously questions the assumed 5% limitation on spot market purchases and believes this limitation has the effect of artificially inflating the apparent need for new resources.

Response: The decision to limit expected spot purchases to 5% or less of each year's hours was based on input from the public input process. Original requests were to plan to build to cover 100% of position. PacifiCorp believes building or buying to cover 100% of the position (the needle peak hour) is excessively conservative; EFOR alone can account for more than 5% for the duration.

The 5% limitation was also observed to mitigate the risk associated with power price volatility. Power price volatility can be considerable. It is true that minimization of power price risk favors being long power more often than being short since prices are unbounded on the upside, but cannot be negative under current market rules. However, a long position, or even a 100% coverage position, requires either more owned or controlled capacity or a large amount of both shaped purchases or call optionality. These positions can be structured and can be cost effective, but this is a very fine level of detail to be shown in an IRP. The 5% limitation is not inconsistent with a prudent spot market exposure, which PacifiCorp is now successfully managing. Recent market experience supports this. Filling the 5% short with peak hour block purchases will create shoulder hour length that will have a high probability of being surplus. This relatively small short position (approximately 5%) is favored on the basis of prudent commodity risk management.

Load Transfers

DPEC states that PacifiCorp stipulated (as a merger condition) to entertain good faith offers to transfer loads to cooperative utilities in Utah and Wyoming, and asserts the IRP should include detailed public analysis of the system-wide effect of transferring identified pockets of load to reduce future demand on PacifiCorp resources. The WPSC comments that the assumption that no major industrial customers will leave the system for the life of the plan should be listed as a key assumption, especially in light of the efforts to allow them this choice.

Response: PacifiCorp remains open to receiving good faith offers. However, as a planning matter, PacifiCorp strongly feels it must plan adequate resources to meet its load obligations. There is no requirement to evaluate disposal of service territory or of customers as part of resource planning Standards and Guidelines. The uncertainty associated with PacifiCorp's total load is sufficiently recognized in the load forecast risk analysis. If there are any load transfers in the future, these will be taken into account in future resource plans. The assumption of no loss of major industrial customers due to retail access is noted as a key assumption.

Load Forecasts

The UDPU suggests including more detail on the models used to develop the retail load forecasts, and an explanation of how the short term and long term models are linked.

Response: PacifiCorp has included more detailed discussion of load forecast modeling in Appendix K of the final IRP.

Rate Impacts

The UCCS states the IRP has not sufficiently shown what the rate impacts of the Portfolios will be on customers. UAE also comments that the IRP fails to provide a meaningful or understandable explanation of the potential customer rate impacts.

Response: PacifiCorp has addressed the customer impacts in the final report, and note that some parties commented that rate impacts of Portfolios were not developed. This level of detail is not a requirement of the IRP rules.

IRP Standards and Guidelines

The UPSC pointed out areas in the Utah Standards and Guidelines that were not explicitly addressed in the draft IRP. These include: 1) a discussion of risks borne by customers versus ratepayers; 2) an analysis of the role of competitive bidding; 3) a plan of different resource acquisition paths as circumstances unfold; 4) a description of how current rate design is consistent with the IRP goals; and, 5) a discussion of whether PVRR is utility cost or total resource cost. Some of these deficiencies were noted by UCCS, too. The UDPU asserts the draft IRP is not consistent with the Utah Standards and Guidelines because it is not the least-cost plan. They also contend that the process was not fully open to the public because some data was considered highly sensitive. The UDPU suggests the document should describe the reasoning for this deviation from the Standards and Guidelines.

Response: The deficiencies have been noted and have been repaired in the Final IRP, through a combination of additional text in the body of the report, and a summary of the compliance to the rules in Appendix N. PacifiCorp disagrees with the UDPU contention that the IRP has not complied with the requirement to develop a least cost plan. This is discussed in the Optimality and Finality discussion above, and in more detail in Appendix N. The UDPU assertion that the IRP has not been developed in a fully public process is unjust. PacifiCorp has devoted serious effort and attention to involve the interested public in the development of the IRP. The public involvement process is fully described in Appendix N. Moreover, as a further means for ensuring the public participants would be informed by data used in the planning which is indeed commercially sensitive, PacifiCorp utilized confidentiality agreements and protective orders to facilitate this involvement, while protecting customers from potentially negative consequences associated with making this data generally available. In sum, PacifiCorp believes the Final IRP is in full compliance with the Standards and Guidelines.

PARTIES WHO PROVIDED WRITTEN COMMENTS

DPEC - Deseret Power Electric Cooperative
IPUC - Idaho Public Utilities Commission staff
LWF - Land and Water Fund of the Rockies, Utah Clean Energy Alliance, and American Wind Energy Association
NRDC - National Resources Defense Council and Northwest Energy Coalition
OPUC - Oregon Public Utility Commission staff
OOE - Oregon Office of Energy
RES - RES North America
RNP - Renewable Northwest Project
SEEP - Southwest Energy Efficiency Project
SLC - Salt Lake City
DCUC - Sierra Club, Utah Chapter
UAE - Utah Association of Energy Users
UCEA - Utah Clean Energy Alliance
UCCS - Utah Committee of Consumer Services
UDPU - Utah Division of Public Utilities
UPSC - Utah Public Service Commission staff
UEO - Utah Energy Office

USM - US Magnesium LLC
WCAC- Wasatch Clean Air Coalition
WDO - William L. D'Olier
WPSC - Wyoming Public Service Commission staff

APPENDIX P – PERFORMANCE ON RAMPP-6 ACTION PLAN

OVERVIEW

This Appendix will summarize the performance on the RAMPP-6 action plan from August 2001 – December 2002.

In the RAMPP-6 action plan, the Company discussed how uncertainties in the market place demand a flexible approach to the short-term action plan. Events since then have done nothing to reduce that uncertainty. Recognizing the difficulty of determining a definitive action plan, the Company focused on three key issues:

1. The cost-effective amount of energy efficiency for 2001 and 2002.

2. The decision year for development of new resources.

3. The risks associated with development of new resources.

In June 2002, the Company was required by a Commission order in Utah (Docket 98-2035-05) to file an update to the RAMPP-6 action plan using updated assumptions. The updated action plan included results of updating key assumptions, some of the near-term planning requirements the Company is facing, and transmission issues. A short-term action plan was developed that included:

1. Re-establishment of an independent IRP Organization.

2. Construction of Gadsby Peakers.

3. Ongoing DSM efforts

4. Release of an RFP for an air-conditioning load control program.

5. Power contracts entered into as a result of an RFP for new resources.

6. Establishment of a tiered rate structure for summer months in Utah.

DSM GOALS FROM RAMPP-6

The DSM goals from RAMPP-6 were to acquire and implement cost-effective DSM, achieving approximately 16.5 MWa of DSM in 2001 and 2002. In addition to its DSM acquisition activities, the Company will continue to support and work with other parties in the development of public funding mechanisms and alternative implementation strategies for DSM and renewable resources.

Performance: The Company achieved 20.13 MWa of DSM in 2001, Table P.1 provides the breakdown by sector and state:

Table P.1 Actual DSM (MWa) Selected for 2001 by Sector and State

	OR	WA	ID	UT	WY	CA	Total
NEEA*	2.51	.72	.575	0.00	0.00	0.00	3.805
Residential	10.01	0.071	.002	1.014	0.00	.007	11.104
Commercial	2.46	0.117	0.00	.62	0.029	.002	3.23
Industrial	1.294	0.634	0.00	.066	0.00	0.00	1.994
Total	16.274	1.542	.577	1.70	.029	.009	20.13

* NEEA – Northwest Energy Efficiency Alliance

The Company achieved 17.84 MWa of DSM in 2002, Table P.2 provides the breakdown by sector and state:

Table P.2 Actual DSM (MWa) Selected for 2002 by Sector and State

	OR	WA	ID	UT	WY	CA	Total
NEEA*	0.42	0.72	0.60	0.00	0.00	0.00	1.74
Residential	0.15	1.26	0.60	4.76	0.00	0.01	6.78
Commercial	2.73	0.63	0.00	1.33	0.00	0.00	4.69
Industrial	2.01	1.74	0.00	0.88	0.00	0.00	4.63
Total	5.31	4.35	1.20	6.97	0.00	0.01	17.84

* NEEA – Northwest Energy Efficiency Alliance

The Company is committed to both existing DSM programs, as well as the development of new DSM programs. Both new and existing programs were modeled in the current IRP along with supply side options to determine the optimal resource portfolio. The existing programs include:

- Energy Exchange – an industrial load management program
- Power Forward – a Utah Summer Awareness program
- Energy FinAnswer Program – engineering and financial assistance (varies by state) for installation of energy efficient motors, heating & cooling, refrigeration, etc.
- Retrofit Incentive Programs – engineering and incentives for energy efficiency measures (OR, WA and UT). Includes incentives for installation of Vending Mi$er (a device that turns off vending machines when not in use).
- Energy Education and Awareness Campaign – Do the Bright Thing
- Compact Fluorescent Bulb Offerings
- On-Site or Web Based Home Energy Audits

DSM programs that are currently being evaluated include:

- Residential and small commercial load control – the contractor has been selected. Currently waiting on internal approval.
- High efficiency residential AC
- Second appliance recycling
- New commercial/industrial load management – curtailable tarriffs

NEW GENERATION

The RAMPP-6 action plan listed two specific actions that were under consideration in 2001 and 2002 to meet near term capacity constraints: 1) the addition of single cycle turbines at the Gadsby site in Salt Lake and 2) the addition of single cycle turbines in West Valley City in Utah. PacifiCorp was also considering building a fourth coal fired unit at the Hunter site in Utah.

Performance: During 2001 and 2002, PacifiCorp leased gas turbine peaking generators with 95 MW capacity to provide electric generation to meet load requirements in Utah. PacifiCorp has replaced these leased gas turbine peakers at its Gadsby Plant with 120 MW (three 40 MW units) Company-owned gas-fired turbines. The turbines went online in late summer 2002.

In September 2001, PacifiCorp, through an independent third party, issued a 'Request for Proposals' for electricity supply that can be delivered into PacifiCorp's Utah Power electric service territory. This process resulted in a lease with PacifiCorp Power Marketing (PPM, PacifiCorp's unregulated marketing affiliate) for new peaking resources in the Utah Power territory and several contracts for peak electricity to be delivered into that territory. The plant become operational in the summer of 2002, and is currently operating at its full capacity.

The Company is still considering building a fourth coal fired unit at the Hunter site in Utah, and has done further evaluation of the cost-effectiveness of this option in its current IRP planning process. In an effort to keep Hunter 4 as an alternative that could become firm and exercisable, the Company is pursing environmental permitting, as well as performing a water assessment to ensure adequate water supply would be available if Hunter 4 were built.

IRP ORGANIZATION

Performance: In response to the changing dynamics within the power industry, PacifiCorp re-established an independent IRP organization within the Commercial and Trading (C&T) organization in the summer of 2001. The organization is staffed with analysts experienced in generation planning, transmission planning, modeling and analysis, market fundamentals, risk analysis and demand-side management. By creating an independent organization PacifiCorp plans to make the IRP process more robust and real-time going forward. In addition, the placement of the IRP process within the C&T organization is intended to assure that the IRP is an integral component of PacifiCorp's business planning process.

SUMMER TIERED RATES

Performance: On November 2, 2001 the Commission approved an inverted block rate structure for residential customers during the months of May through September. Beginning in May of 2002 rates are 6.3029¢ per kWh first 400 kWh and 7.0866¢ per kWh all additional kWh. This rate structure is intended to encourage efficient energy use during the peak summer months, May through September.

In addition to the inverted rate structure change, PacifiCorp also redesigned the residential Time of Use rate plan, reducing the basic charge to provide a better opportunity for customers to effectively exercise the plan and to encourage greater plan participation.

To communicate these rate changes to customers, PacifiCorp produced a bill insert that began appearing in customer billings in May 2002. The insert addresses what the changes are, why they were made, and provides energy-savings tips so that customers can take full advantage of the changes. PacifiCorp has provided the commission staff copies of the inserts for the purpose of answering possible customer questions surrounding the rate changes/customer communication.