Exhibit No. ___ (APB-8)
Docket Nos. UE-050684 and UE-050412
Witness: Alan P. Buckley

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP, d/b/a Pacific Power & Light Company, Respondent.	DOCKET NO. UE-050684
In the Matter of the Petition of PacifiCorp, d/b/a Pacific Power & Light Company for an Order Approving Deferral of Costs Related to Declining Hydro Generation	DOCKET NO. UE-050412

EXHIBIT TO
TESTIMONY OF

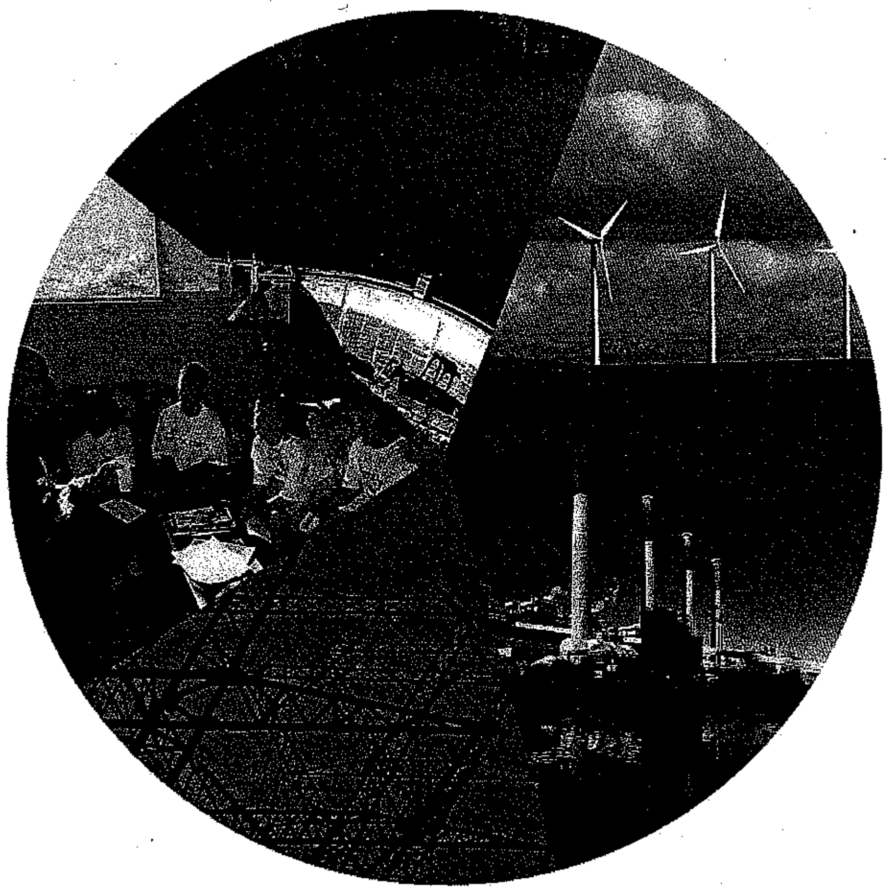
ALAN P. BUCKLEY

For
STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

PacifiCorp's 2003 IRP:
"Integrated Resource Plan – 2003"
(EXCERPTED)

November 3, 2005

Integrated Resource Plan 2003



Assuring a bright future for our customers

PACIFICORP
PACIFIC POWER UTAH POWER

Docket No. UE-050684
Exhibit No. _____
Page 1

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

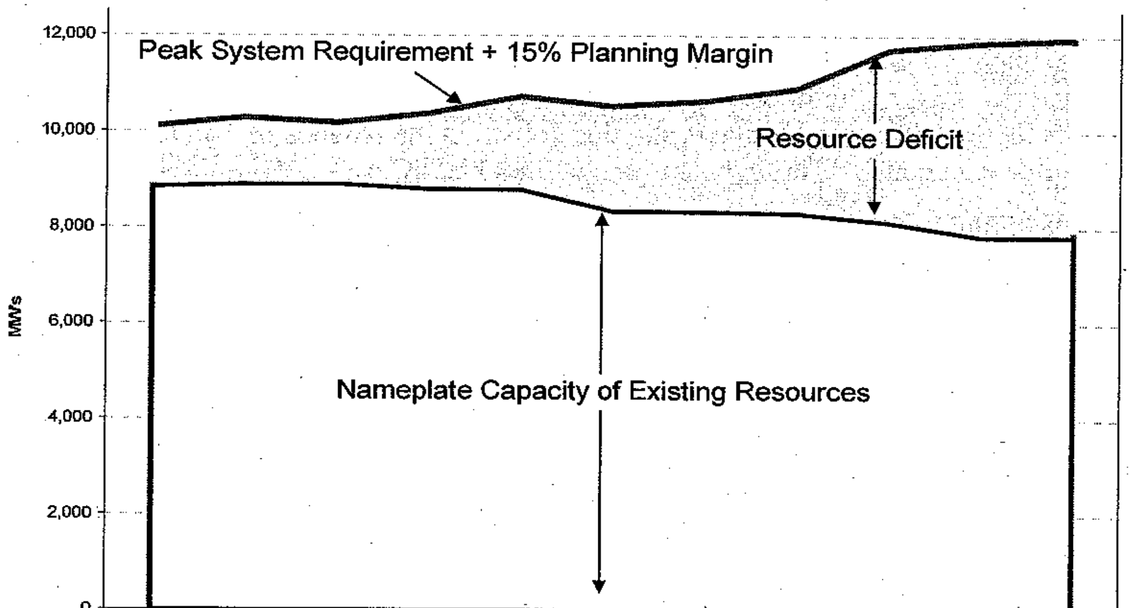
PacifiCorp serves approximately 1.5 million retail customers in service territories comprising about 135,000 square miles in portions of six Western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The service territory has diverse regional economies ranging from rural, agricultural,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



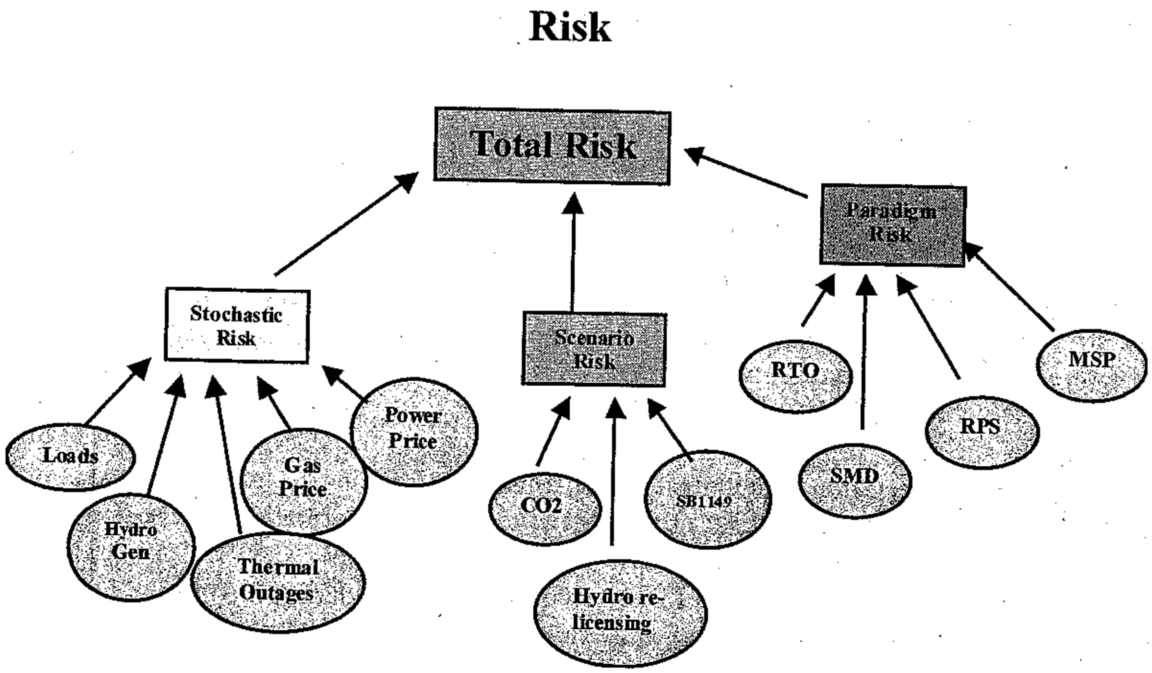
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Pk Rqmt + 15%	10,090	10,288	10,176	10,379	10,731	10,531	10,641	10,893	11,712	11,869	11,936
Existing Capacity	8,833	8,894	8,893	8,800	8,788	8,335	8,335	8,299	8,119	7,820	7,820

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.
- 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).

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.

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.

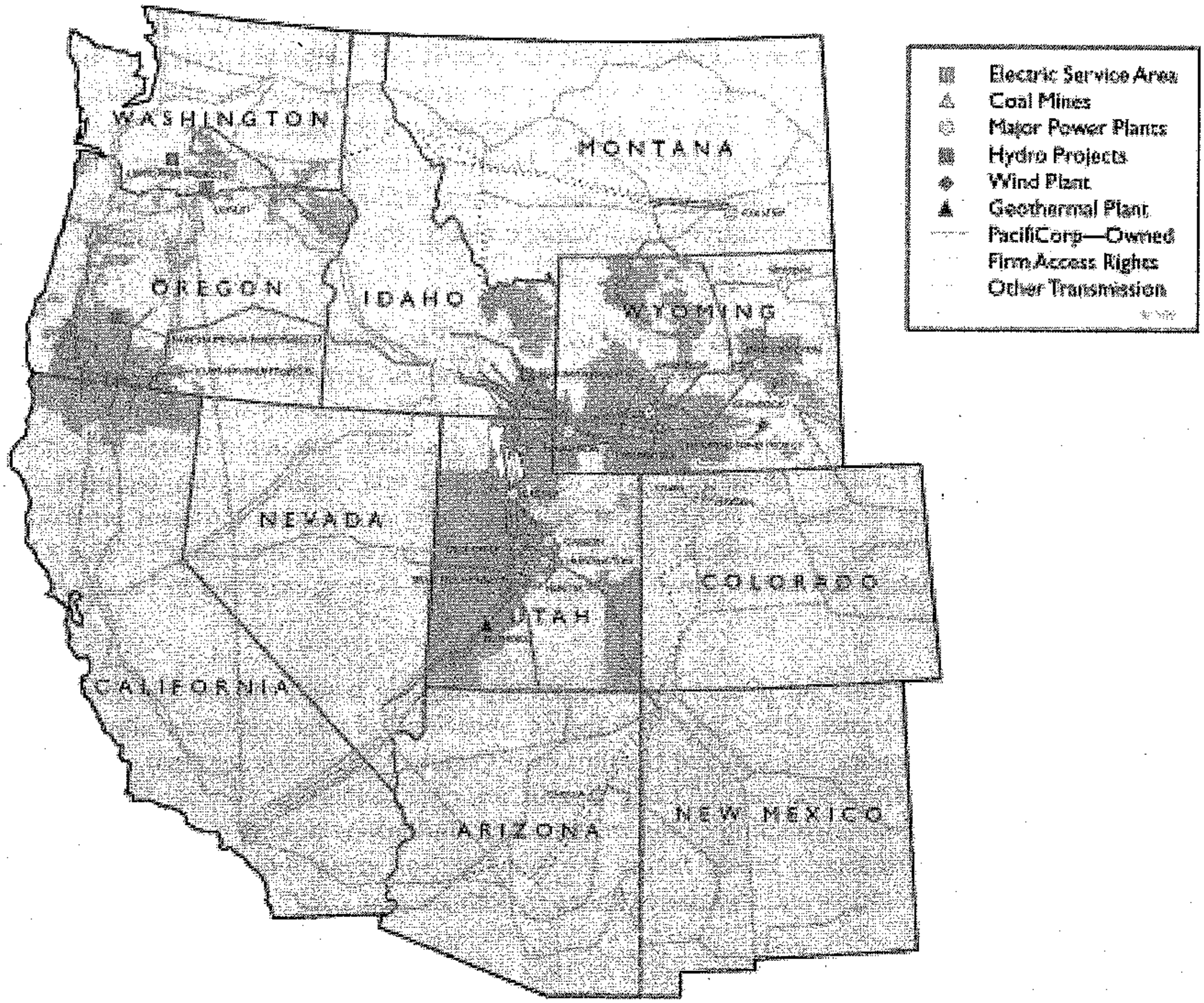
Service Territory

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



<u>PacifiCorp Retail Load</u>

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 Fish Creek	1952	11.0	12.0
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

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[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.

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
- 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

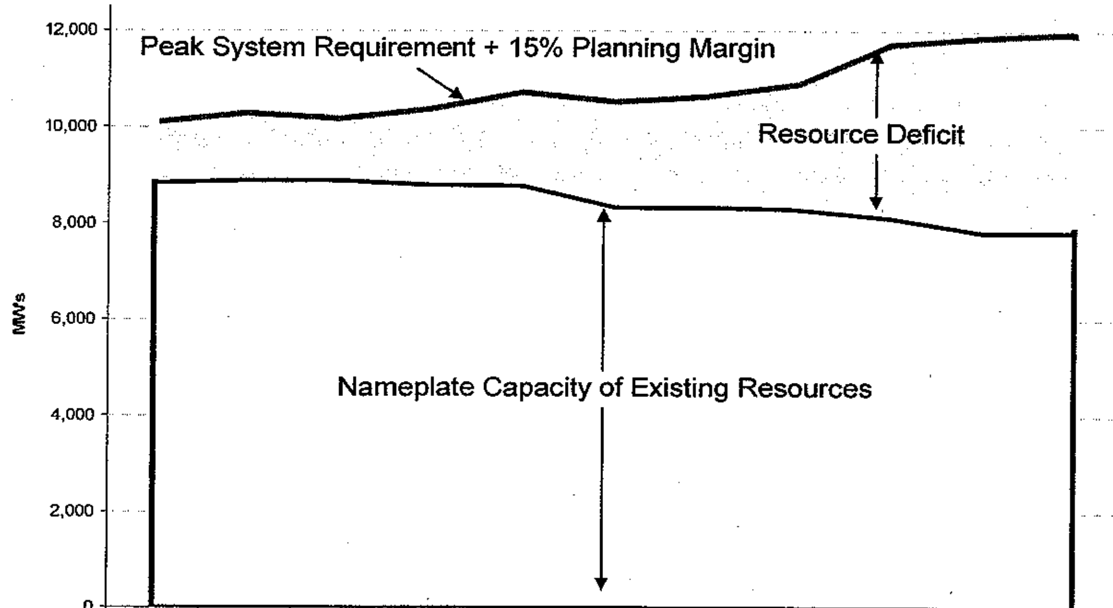
PacifiCorp's firm transmission rights must be analyzed with caution. At times, the sum of imports "available" according to stated contract rights do not equal the transfers physically available to the system. Such inequalities occur because transmission paths and system subsets operate in an interrelated 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.

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).

Figure 2.3 PacifiCorp West Gap Analysis

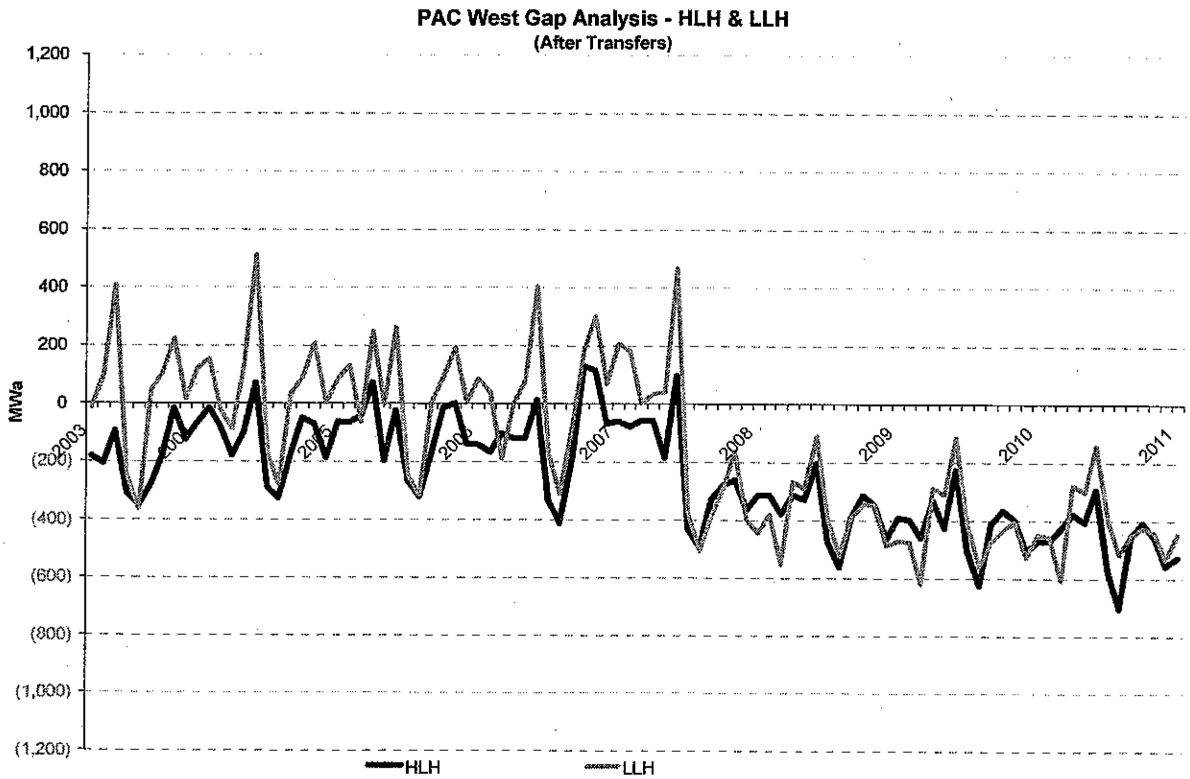
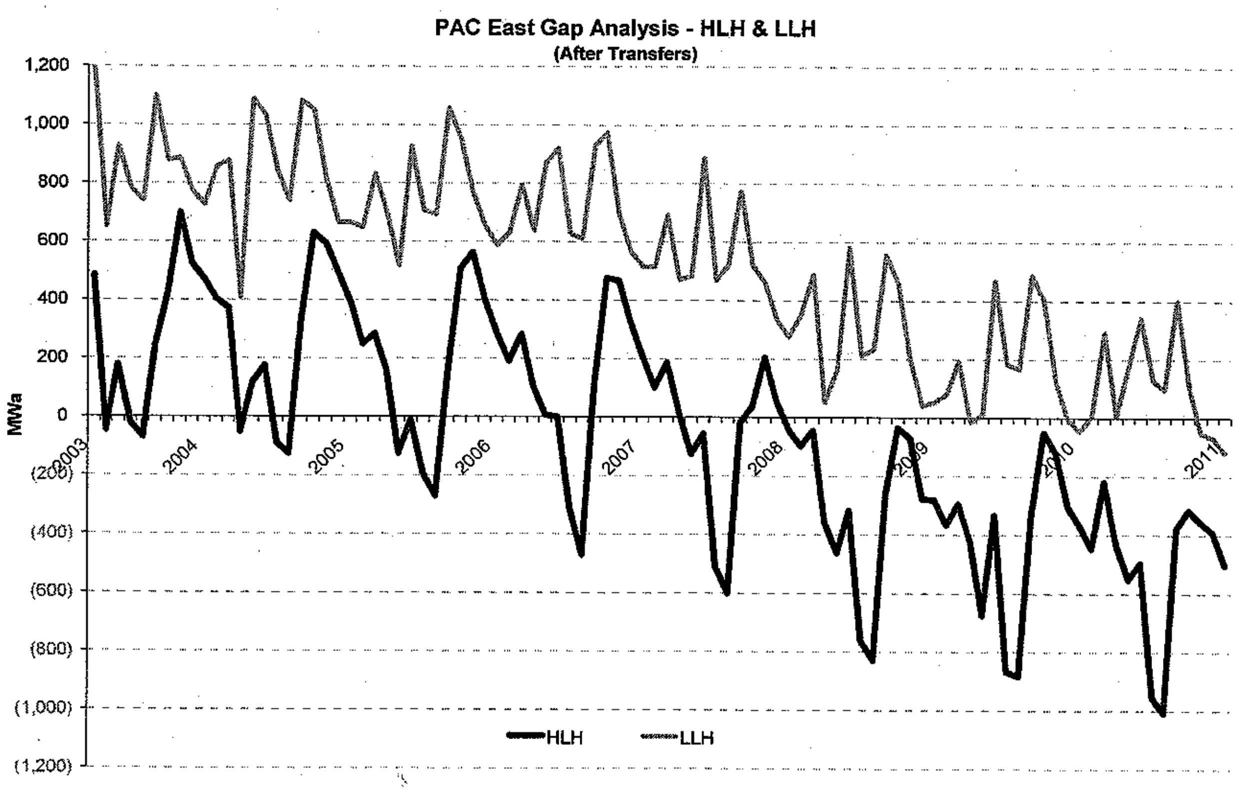


Figure 2.4 PacifiCorp East Gap Analysis



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.

PacifiCorp East

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.

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.

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.

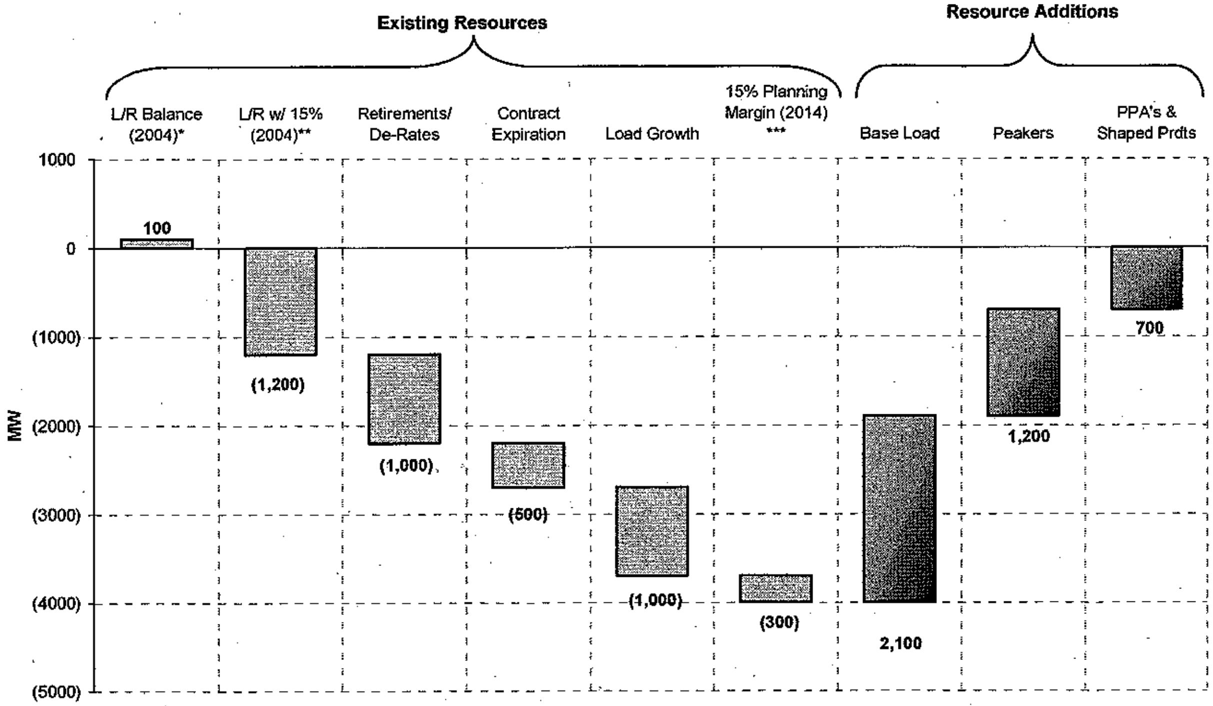
Table 8.1 is a summary of the total MW, timing and capital cost associated with specific resources contained in Diversified Portfolio I. A more comprehensive summary of this portfolio can be found in Appendix D.

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.	2 & 3
3	PacifiCorp needs to procure approximately 500 MW of base load resource in the East of the system by April 2008.	4
4	PacifiCorp needs to procure 200 MW of peaking resources for the East side of the system for operation in 2006.	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 • 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.	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	2. Procure a base load unit in the East of the system for operation in 2008. 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. 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

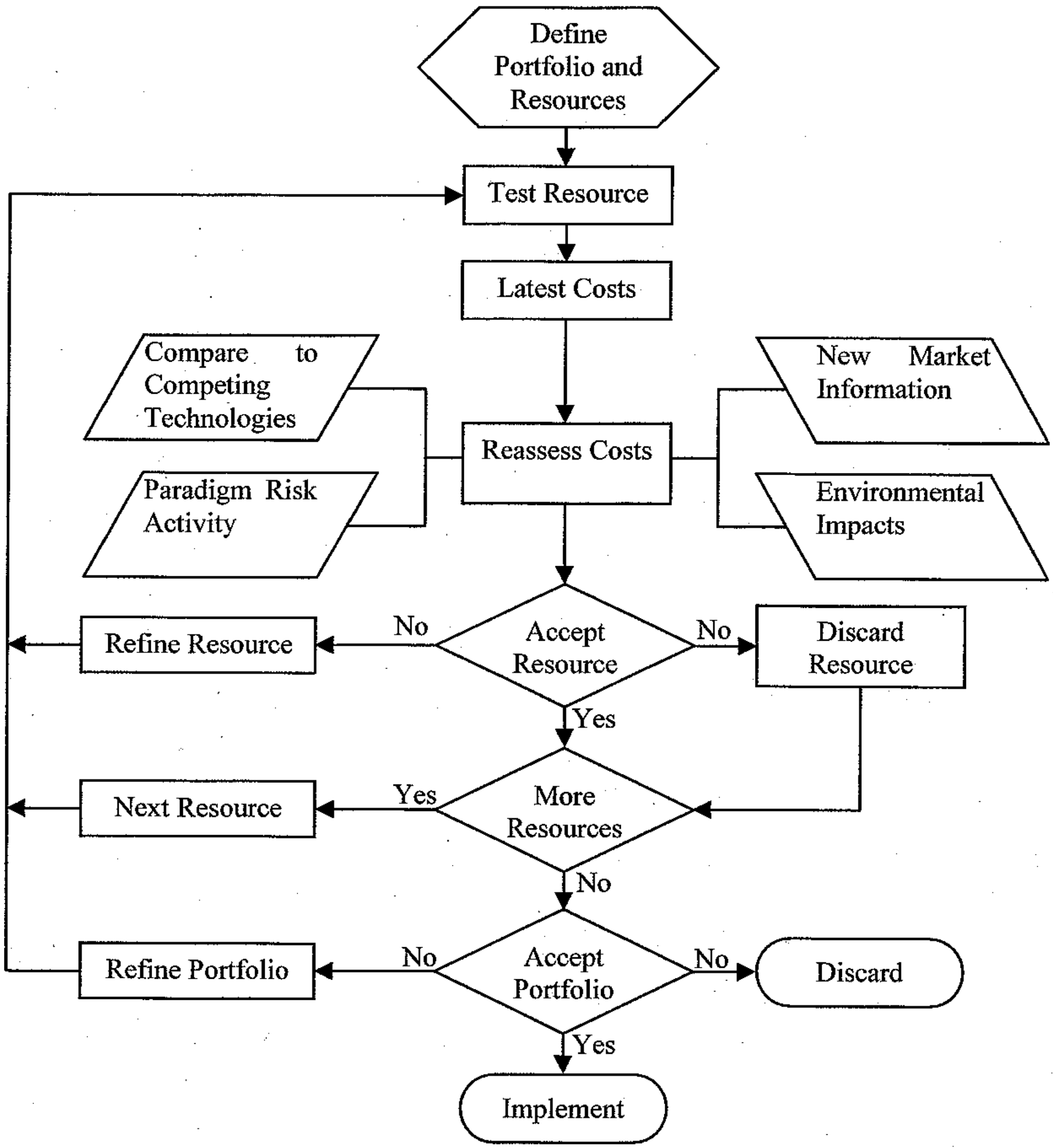
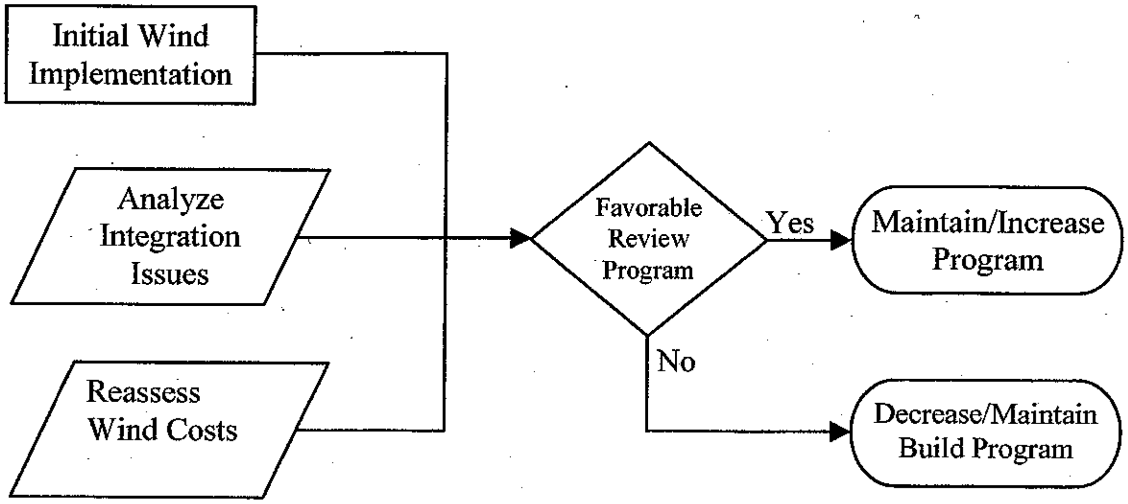


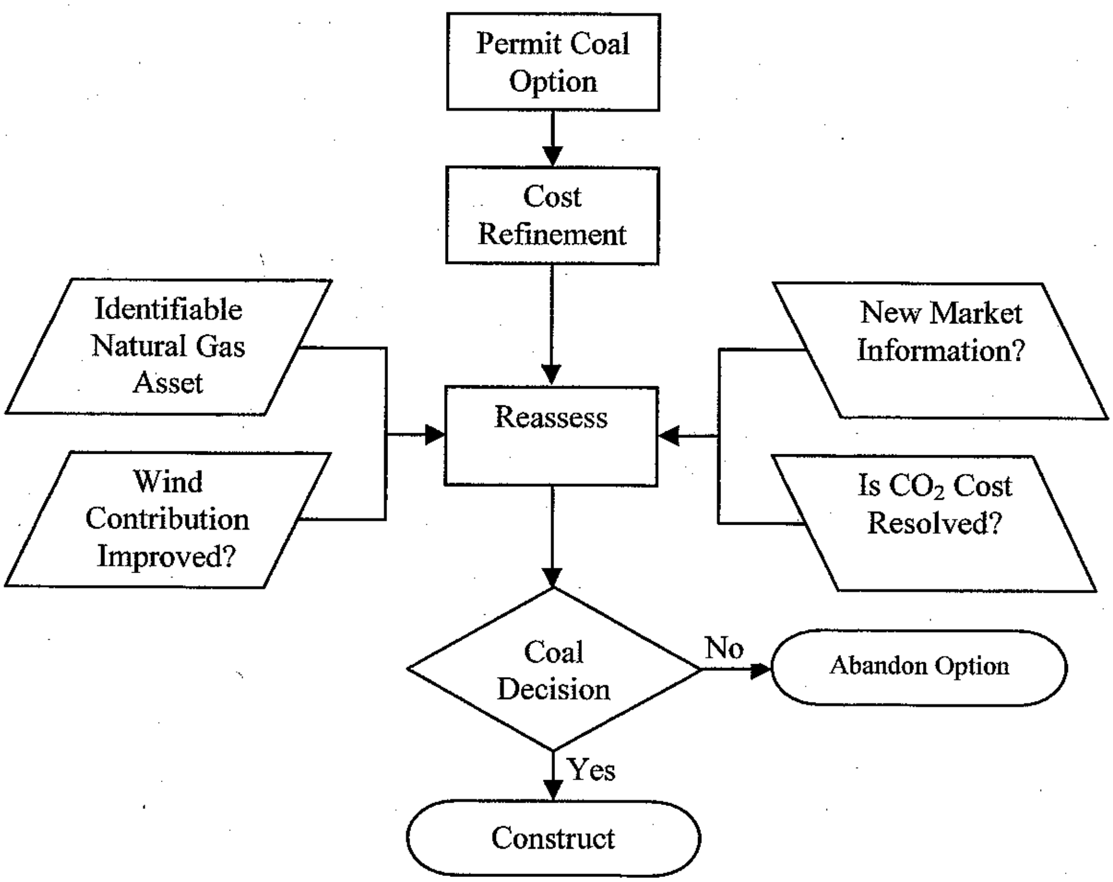
Figure 9.2 addressed the decision process associated with the wind (and other renewables) resources in the Action Plan. The wind build strategy allows time for all parties to develop a greater understanding of the uncertainties associated with wind. The level of wind resource ultimately procured has 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.