Exhibit No. ___ (APB-5)
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

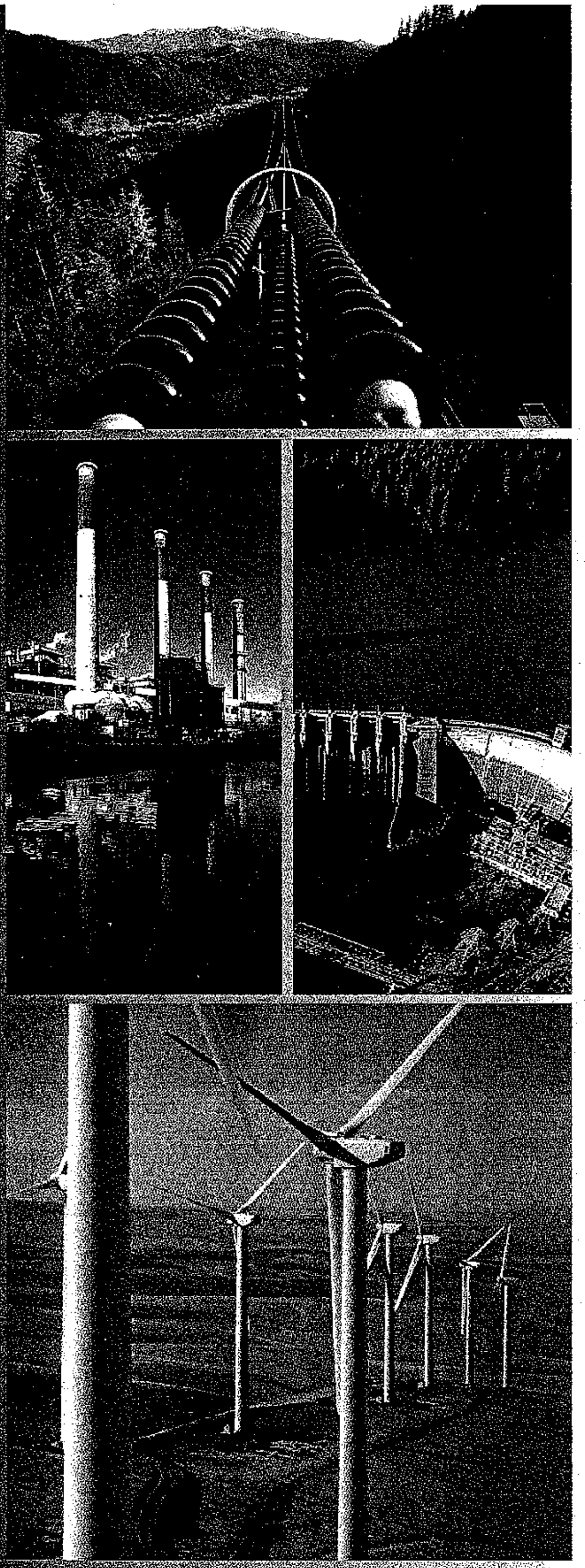
EXHIBIT TO
TESTIMONY OF

ALAN P. BUCKLEY

For
STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

PacifiCorp's 2004 IRP:
"Integrated Resource Plan – 2004"
(EXCERPTED)

November 3, 2005



Integrated Resource Plan 2004

Assuring a bright future for our customers

PACIFICORP

PACIFIC POWER UTAH POWER

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.

For more information, contact:

PacifiCorp
IRP Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
IRP@PacifiCorp.com
http://www.PacifiCorp.com

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EXECUTIVE SUMMARY

SUMMARY

The purpose of PacifiCorp's Integrated Resource Plan (IRP) is to provide a framework of future actions to ensure PacifiCorp continues to provide reliable, least cost service with manageable and reasonable risk to its customers. This IRP was developed in a collaborative public process with considerable involvement from customer interest groups, regulatory staff, regulators and other stakeholders. The analytical approach used conforms to all State Standards and Guidelines, and results in a Preferred Portfolio representing the best combination of resource additions to meet future customer needs. PacifiCorp is filing this IRP with its state regulatory agencies and requests that they acknowledge and support its conclusions, including the proposed Action Plan.

PacifiCorp's Planning Philosophy

Integrated resource planning is a primary driver in PacifiCorp being an excellent regulated utility providing safe, reliable, low cost power to its customers. The 2004 IRP will provide the guidance and rationale for significant resource procurements over the next several years.

PacifiCorp's planning philosophy is that an IRP will be most successful if it is *owned* by both the Company and by its stakeholders. PacifiCorp is committed to the IRP process and maintains a full time Integrated Resource Planning department with specialized expertise to ensure the best possible IRP. This department, working with experts from across PacifiCorp, employing very sophisticated analytical tools, and using the best available data, developed the 2004 IRP.

It is equally important that PacifiCorp's regulators, customers and other important stakeholders contribute to and understand the IRP. To this end, the planning process is open and transparent, engaging stakeholders in a year-round collaboration. Many suggestions for improvements to the plan were made and incorporated as the planning progressed. Many improvements to the report were also made, in response to comments received from participating stakeholders.

During the planning process, and in alignment with PacifiCorp's obligations to its customers and shareholders, all policy judgments and decisions are ultimately made by PacifiCorp. PacifiCorp will implement the Action Plan, while also maintaining the flexibility to adjust to future changes and opportunities. The IRP Action Plan is in full alignment with business plans, and will guide future resource procurement decisions. By these means, the IRP is PacifiCorp's plan.

Current 2003 IRP Procurement Activity

The 2003 IRP identified the need for procurement of two natural gas supply side resources, 1,400 MW of economic renewable resources, and both Class 1 and Class 2 demand side resources. Since the filing of the 2003 IRP[1], PacifiCorp has:

- Procured two natural gas resources via the issuance of supply side solicitations. These plants are scheduled to come online in the summers of 2005 and 2007 respectively.

[1] The 2003 IRP references the IRP submitted by PacifiCorp in January 2003 – not to be confused with the October 2003 IRP update. This 2004 IRP is the current biennial IRP which, although one year apart in naming convention from the 2003 IRP, is two years apart in time.

- Issued a Request for Proposals (RFP) for renewable resources in February 2004 resulting in over 6,000 MW of renewable offers, approximately 1,400 MW of which have the potential to be cost-effective.
- Selected three new cost-effective programs from a demand side management (DSM) RFP issued in June 2003 that are expected to be launched in early 2005.

New Resource Needs

The 2004 IRP builds upon the procurement foundation established by its predecessor plan. This IRP proposes a significant addition of new resources over the first 10 years of the 20-year study horizon. Over time, PacifiCorp expects its existing resources to diminish significantly concurrent with an expected increase in supply obligations. Load and system peak growth, hydro relicensing and contract expirations will increase the gap between demand and supply. Prompt and focused action is needed to close this gap and shield PacifiCorp and its customers from unacceptable levels of cost, reliability and market risk.

The Preferred Portfolio proposes the addition of 177 MW of Class 1 DSM and 2,629 MW of thermal generation capacity. In addition to the resources identified in the Preferred Portfolio, PacifiCorp will continue to procure up to 1,200 MW of shaped capacity through Front Office Transactions on a rolling forward basis, expects 100 MW of capacity through Qualified Facilities (QF) contracts, and will continue to procure the 1,400 MW of economic renewable resources that were first identified in the 2003 IRP. Furthermore, PacifiCorp will procure 250 MWa of base Class 2 DSM and pursue an additional 200 MWa of cost effective DSM for a potential total of 450 MWa over the ten year horizon.

Results and Key Findings in the IRP

Results and key findings in the IRP include:

- The 2,629 MW of thermal generation capacity consists of four thermal units in the east (two fueled with coal and two with natural gas) and one natural gas unit in the west.[2]
- The most robust resource strategy relies on total resources creating a diverse portfolio of resources including renewables and demand side management combined with natural gas and coal-fired generating resources.
- Two major issues hang over the most significant resource choices that PacifiCorp must make (i) the future cost of natural gas and (ii) the future cost of or constraints on air emissions, and carbon dioxide emissions in particular. PacifiCorp believes it has adequately addressed these risks in the analysis, based on our current understanding of these issues.
- Demand side management continues to be an important and cost-effective resource for PacifiCorp. DSM additions resulted in new generating resources being delayed. The first two east side resources are delayed 1 year each, and a west side resource is delayed 2 years - pushing it beyond the ten-year portfolio planning window.
- The Present Value Revenue Requirement (PVRR) for the group of lowest-cost, risk-adjusted portfolios differed by only $48 million, or 0.4 percent. This narrow cost range indicates a

[2] Resources evaluated in each portfolio are considered proxy resources and represent the fuel type and operating characteristics that best fit the deficit position. The actual type of resource acquired is made during the procurement process.

degree of flexibility in specifying and procuring needed resources during the Action Plan time horizon.
- In response to stakeholder comments, a detailed study was conducted to determine the optimal planning margin for the PacifiCorp system. The results of this study found the optimal planning margin for the PacifiCorp system to be 15%.
- Also in response to stakeholder comments, an evaluation of the wind resources providing energy to PacifiCorp's system was conducted to determine what the appropriate contribution to planning margin should be for these resources. The evaluation resulted in a 20% contribution to planning margin by wind resources.

COMPARISON OF THE 2003 IRP TO THE 2004 IRP

The following compares the 2003 IRP to the 2004 IRP over the first ten years of the 20-year IRP study horizon.

- Load Forecast – The 2004 IRP exhibited a growth in energy and peak load over the 2003 IRP.
- Wind – The 2004 IRP has no significant difference in renewable resource assumptions from the 2003 IRP with the exception of the contribution to planning margin of wind resources. The 2004 IRP gives a 20% contribution to planning margin for wind resources whereas the 2003 IRP assumed no contribution to planning margin.
- Purchases – The 2004 IRP, like the 2003 IRP, contains shaped contracts for system balancing purposes.
- Demand Side Management – The 2004 IRP proposes an increase in economic Class 1 DSM procurement and a change in Class 1 DSM modeling methodology. Chapter 5 details the changes in methodology.
- Thermal resources – The 2004 IRP Preferred Portfolio shows a decrease in needed thermal resources.
- Procured thermal resources – Since the 2003 IRP was published, approximately 1,100 MW of gas-fired thermal resources specified in the 2003 IRP have been procured via a competitive RFP process.
- Planning margin – The planning margin of 15% did not change between the 2003 IRP and the 2004 IRP.

THE CHANGING CONTEXT OF INTEGRATED RESOURCE PLANNING

The practice of integrated resource planning must be adaptive to changing circumstances if it is to meet its objective of guiding resource choices to the lowest cost and lowest risk alternatives.

The electricity industry market environment has continued to evolve since PacifiCorp's last IRP. Shifting federal policy and many state regulatory initiatives continue to encourage competitive markets and at the same time are refocusing on the role of load serving entities in ensuring adequacy of supplies. Various state experiments with retail competition also continue. The current business environment can best be described as something of a hybrid between traditional utility and competitive market models, with no clear end-state in sight.

Currently, there is nothing in this shifting picture of regulation and competition that suggests PacifiCorp should not continue to plan for the future requirements of its existing customers in all jurisdictions it serves. Moreover, the Company's Multi-State Process continues to emphasize that the lowest aggregate cost system should be developed. Going forward PacifiCorp's portfolio of supplies remains tied to broader wholesale energy markets.

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

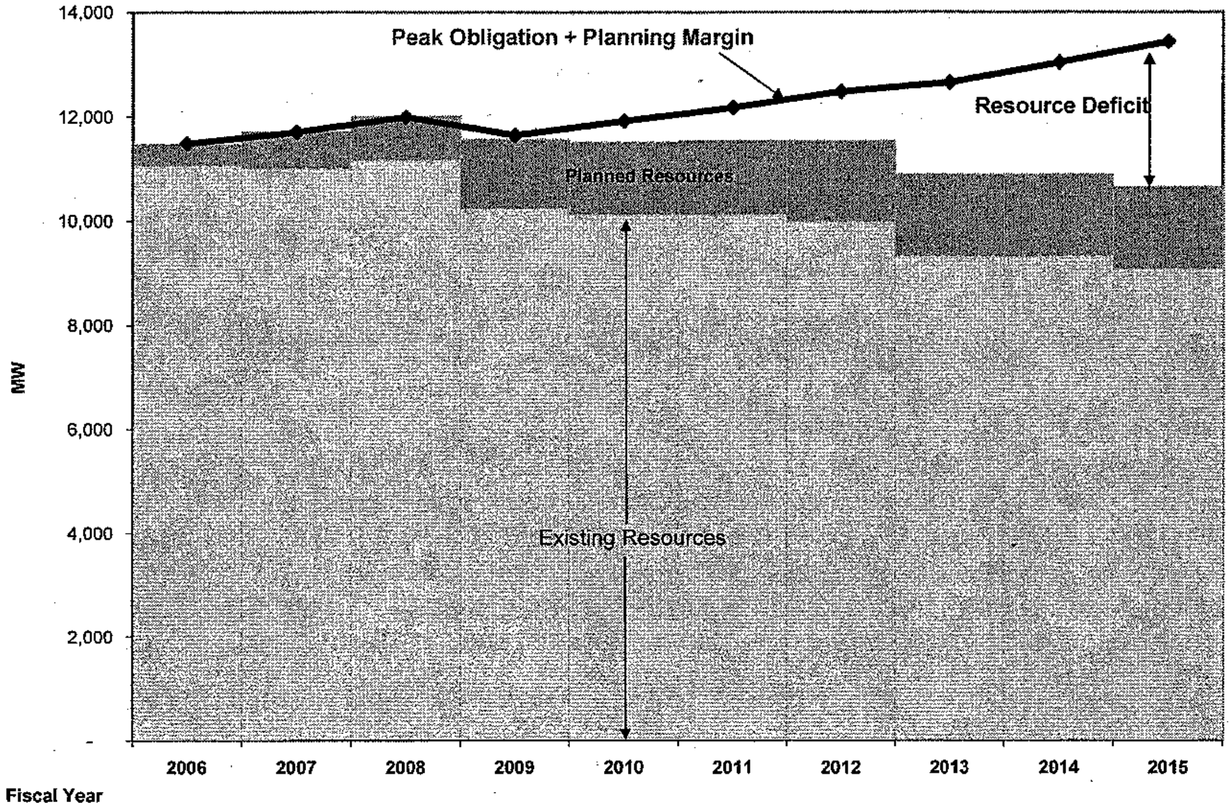
RESOURCE NEEDS ASSESSMENT

PacifiCorp forecasts an average annual peak load growth rate of 3.8% in the East and 1.5% in the West, with a total peak growth of 3.0% per year over the forecast horizon. Given uncertainties of economic growth and other factors, the net system growth in PacifiCorp's load could vary. As mentioned earlier, resources available to PacifiCorp to serve this load will diminish. This difference between load and existing resources is an imbalance referred to as the *gap*, and will grow over time.

The difference between system obligations and PacifiCorp resources defines the shortfall in supply. Figure ES.1 below is an illustration of PacifiCorp's peak system requirement with a 15% planning margin compared to the capacity of Existing and Planned Resources as they are expected to exist in the future.[3]

[3] Existing Resources refers to the sum of existing resources (Thermal, Hydro, Purchases, Interruptible, and Class 1 DSM). Planned Resources are resources that can be predicted with some degree of confidence and consist of up to 1,200 MW of shaped balancing contracts, 20% planning contribution from 1,400 MW of renewable resources, and 100 MW of Utah QF contracts. For more details on Existing and Planned Resources see chapter 3.

Figure ES.1 – PacifiCorp Coincident Peak Capacity Chart*



Resources	11,484	11,714	12,013	11,566	11,526	11,546	11,537	10,897	10,895	10,657
Obligation+15%	11,485	11,701	11,988	11,639	11,916	12,177	12,478	12,650	13,035	13,434

* The TransAlta power purchase agreement ends in FY 2008, partially offsetting the addition of Lake Side Power Plant. In FY 2009 the West Valley lease expires and the Clark County Load Servicing contract ends. In FY 2012 the BPA peaking contract ends.

Beginning in FY 2009 the system becomes capacity deficient and the deficit steadily grows to approximately 2,800 MW by FY 2015.

RESOURCE ALTERNATIVES

There are a large number of demand side and supply side options that could be used to fill 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
- Distributed Generation
  - Standby Generation
  - Combined Heat and Power (CHP)

- Supply side Resources
  - Renewables (wind, geothermal)
  - Coal (Pulverized and Integrated Gasification Combined Cycle)
  - Natural gas (SCCT, CCCT with DF, IC Aero SCCT)[4]
  - Compressed Air Energy Storage
  - Hydro Pumped Storage
- Market Purchases
- Transmission

A description of all supply and demand side resources identified for this IRP are discussed in Chapter 6, followed by an assessment of how the resources were evaluated in the 2004 IRP.

RISKS AND UNCERTAINTIES

Resource planning must consider many future risks and uncertainties. While the need for planning to account for the uncertainties is clear, the general techniques for effectively incorporating risk analysis into utility resource plans have been more elusive. PacifiCorp has adopted a methodology to evaluate how alternative resource options perform against the risks and uncertainties in three categories: Stochastic, Scenario and Paradigm risks.

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 with a probabilistic distribution. PacifiCorp's analysis treats the following variables as Stochastic risks.

- Retail Loads
- Electricity Price
- Natural Gas Price
- Hydroelectric Generation
- Thermal Unit Availability

Scenario Risks

Scenario risks cannot be reasonably represented by a known statistical process. Instead, a fundamental change or a structural shift is made to the expected value of some parameter. This risk category is intended to embrace abrupt changes in certain risk factors, such as introduction of high carbon dioxide (CO_2) allowance costs. The probability of high CO_2 costs cannot be determined with a reasonable degree of accuracy. Therefore, a scenario of this occurrence is created without applying a probability distribution. The measure of Scenario risk is the difference between the present value revenue requirement (PVRR) generated by applying different scenarios.

[4] SCCT – Simple Cycle Combustion Turbine, CCCT – Combined Cycle Combustion Turbine, DF – Duct Firing, IC Aero SCCT – Intercooled Aeroderivative Simple Cycle Combustion Turbine.

The Scenario risks addressed in the 2004 IRP include:

- Impact of various CO_2 emissions allowance rates ($0/ton, $10/ton, $25/ton and $40/ton in 1990 dollars)
- Changes in natural gas prices that could occur due to fundamental shifts in the market – a 10% increase in the most recent gas price forecast

Paradigm Risks

A paradigm shift is a fundamental structural change to the electricity business model associated with a material shift in market structure or regulatory requirements. The key Paradigm shift considered within this IRP is the introduction of Grid West, an independent regional transmission entity.

Since the details of such fundamental changes are not generally known, associated risks do not lend themselves to quantitative analysis. Therefore the impacts of Grid West have not been explicitly modeled in the 2004 IRP, but are considered in the IRP action plan. While not explicitly modeled, Paradigm risks cannot be ignored. Paradigm risks, as they arise, ultimately require a well reasoned response arrived at between PacifiCorp, its regulators and the public.

THE IRP 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 hourly dispatch model used for the analysis includes 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:

- **Step 1: Portfolio Development** - The first step in the analytical process is the formulation of resource portfolios. The formulation consists of determining the resource need (the Load & Resource balance), composing candidate resource options to fill that need, and building portfolios according to development guidelines.

- **Step 2: Operational Simulation** - Next, each portfolio, consisting of the existing resource base and new additions, is simulated deterministically using a production cost model.

- **Step 3: Cost Analysis** - Each portfolio's system operating costs are then combined with the corresponding capital costs, yielding the PVRR, the main cost metric.

- **Step 4: Screening** - The performance of each of the portfolios is evaluated based on total cost (PVRR), other measures of portfolio performance, and characteristics of interest for risk analysis. This screening process results in a narrowing of portfolios to a list of candidates for risk analysis.

- **Step 5: Risk Analysis** - The risk analysis evaluates the performance of candidate portfolios under a large number of possible futures using Monte Carlo and deterministic scenario simulations.

- **Step 6: Selection of the Preferred Supply Side Portfolio** - Using results from the deterministic, stochastic, and scenario model runs, along with the customer impact results and non-modeling considerations, a single portfolio is selected that has the best balance of cost and risk. This is the preferred supply side portfolio.

- **Step 7: Selection of the Preferred Portfolio** - Class 1 DSM analysis is performed on the preferred supply side portfolio in order to further improve the PVRR, resulting in the final Preferred Portfolio.

- **Step 8: Class 2 DSM Analysis** - Once the Preferred Portfolio is identified, Class 2 DSM decrement analysis is performed to estimate the system production cost benefits resulting from DSM-related load reductions. These values will be used to evaluate potential programs going forward.

- **Step 9: Stress Case Analysis** - Stress case portfolios are devised and simulated to determine the impacts of base assumption changes or alternate supply options.

Three key assumptions were particularly important to the analytical approach:

- Where possible, the analytical approach presumed new resources were actual specific assets.
- The analysis assumed no renewal of long-term purchases or sales contracts.
- Only firm transmission was included to ensure its availability to provide service.

The analytical approach outlined above results in the determination of the Preferred Portfolio which represents the best combination of resource additions to meet future customer needs.

RESULTS

Applying the previously described analytical methodology yielded a large body of results. Analyzing these results to determine a Preferred Portfolio requires evaluating seven areas to identify their context and meaning:

- **Candidate Portfolio Evaluation Results:** This section presents the expected costs of each candidate portfolio based on deterministic simulations. From these results, a set of portfolios is recommended for risk evaluation.

- **Risk Evaluation Results:** Risk evaluation summarizes portfolio variability due to the Stochastic and Scenario Risks.

- **Customer Impacts:** Customer impacts expresses portfolio results from the perspective of incremental rate impact for customers.

- **Selection of the Preferred Supply Side Portfolio:** This provides a consolidated view of all the portfolio evaluation results to indicate which supply side portfolio is the most desirable.

- **Overall Preferred Portfolio:** This presents PacifiCorp's Preferred Supply Side Portfolio after the addition of DSM load control programs (Class 1).

- **DSM Decrement Analysis:** This presents the decrement values for Class 2 DSM program evaluations based on the Preferred Portfolio.

- **Stress Case Portfolio Evaluation Results:** This presents the expected costs of portfolios designed for sensitivity analysis of certain portfolio assumptions.

The results of the analysis confirm that Portfolio E with Class 1 DSM is the Preferred Portfolio. The Preferred Portfolio represents the best balance of cost and risk for addressing PacifiCorp's long-term resource needs based on forecasted demand. The Preferred Portfolio consists of a balanced mix of resource additions, and ranks at or near the top of most stochastic risk measures considered. Furthermore, the Preferred Portfolio doesn't stand out as a risky portfolio in terms of the CO_2 cost and high gas cost Scenario Risks. Finally, the Preferred Portfolio ranks among the lowest of all candidate portfolios in terms of deterministic PVRR. Table ES.1 below (in PacifiCorp fiscal years) provides an overview of the resources that are included in the Preferred Portfolio.

Table ES.1 – Preferred Portfolio

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S							575				575
	Brownfield Coal	WY										383	383
	Dry Cool CCCT w/ DF	Utah-S					525						525
	Wet Cool CCCT w/ DF	Utah-N									560		560
	DSM, Summer Load Control	East									44		44
	DSM, Summer Load Control	East				44							44
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	DSM, Summer Load Control	West									45		45
	DSM, Summer Load Control	West				44							44

ACTION PLAN

The Action Plan details 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 be revisited and refreshed no less frequently than annually.

The Action Plan also aims to ensure PacifiCorp will continue to meet 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 procuring needed resources.

State guidelines require PacifiCorp to develop a short-term (2-4 year) Action Plan. The Action Plan detailed below in table ES.2 includes an action item for any decision that needs to be made in the next 2-4 years. All portfolio resource decisions outside this period will be re-evaluated in subsequent IRPs.

Table ES.2 – Key Elements of the Action Plan

Action Item	Timing*
Renewables - pursue 1,400 MW of economic renewable resources	RFP 2003B currently underway, subsequent RFPs to follow as needed
DSM – pursue 88 MW of cost effective Class 1 DSM	Summer-Fall 2005
DSM – pursue 200 MWa of new cost effective Class 2 DSM	Winter 2005
Distributed Generation – include CHP and standby generation as eligible resources in supply-side RFPs	Include as part of a supply side procurement process
Thermal Resource - FY 2010	Fall 05-Summer 06
Thermal Resource - FY 2012	Spring 06-Spring 07
Transmission - actively participate in regional transmission initiatives (RMATS, Grid West, etc.)	On-going
Incorporate Capacity Expansion Model as a modeling tool	Currently underway

*See chapter 9 for more detail on action item timelines.

<u>Implementation</u>

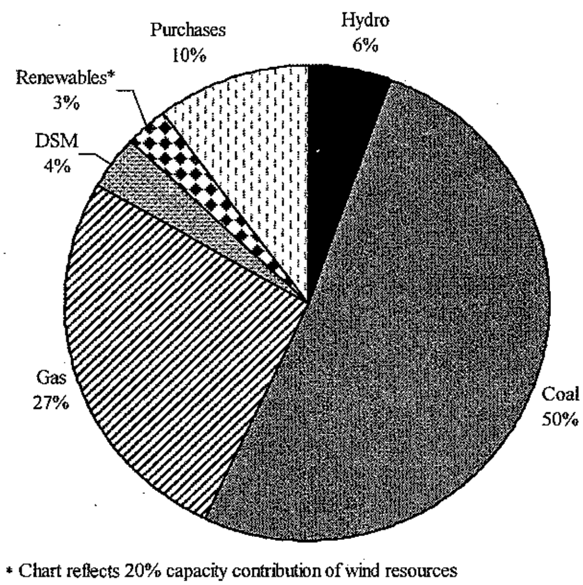
PacifiCorp intends to implement many elements of the Action Plan utilizing a formal and transparent Procurement Program. The IRP has determined the need for resources with considerable specificity, and identified the desired Portfolio and timing of need. The IRP has not identified specific resources 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.

Prior to the issuance of any supply side RFP, PacifiCorp will determine whether the RFP should be "all-source" or if the RFP will have limitations as to amount, proposal structure(s), fuel type or other such considerations. Benchmarks will also be determined prior to an RFP being issued and may consist of the then-current view of market prices, a self-build option, a contractual arrangement, or other such benchmark alternatives. Externalities will be determined based on the form and format of each procurement process and it is anticipated that the assumptions utilized will be consistent with what is in the IRP unless such assumptions are not applicable or new/updated information becomes available to inform the process.

CONCLUSION

The combination of new resources identified in the Preferred Portfolio and the existing and planned resources results in a more diversified resource portfolio for PacifiCorp. The pie chart in Figure ES.2 shows the capacity of PacifiCorp's existing, planned, and IRP resources as a percent of peak obligation (peak load + firm sales) for FY 2015.

Figure ES.2 – FY 2015 Resource Composition



The IRP is not only a regulatory requirement but is also the primary driver in the Company's business planning and resource procurement process. It is critically important that state regulatory commissions acknowledge and support this IRP, including the Action Plan.[5] PacifiCorp's shareholders and the financial community take into account the governmental and public response to the IRP when making capital allocation and investment decisions. This allows PacifiCorp to better manage both customer and company risk by maintaining an investment grade credit rating in order to procure new resources on the best available financial terms. This translates into direct benefits for our customers.

[5] An IRP is submitted to Wyoming as an informational filing, Wyoming guidelines do not require an IRP. PacifiCorp has approximately 43,000 customers in California. California guidelines exempt a utility with under 500,000 customers from filing a formal IRP. Under this guideline PacifiCorp will be filing the IRP in California as an advisory filing only.

2. PACIFICORP OVERVIEW

PacifiCorp is a regulated electricity company operating in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. As a vertically integrated electric utility, PacifiCorp owns or controls fuel sources such as coal and natural gas, and uses these fuel sources, as well as wind, geothermal and hydroelectric resources, to generate electricity at its power plants. This electricity, together with electricity purchased on the wholesale market, is then transmitted via a grid of transmission lines throughout PacifiCorp's six-state region. The electricity is then transformed to lower voltages and delivered to end-use customers through PacifiCorp's distribution system. The retail electric utility business is conducted using the business names Pacific Power and Utah Power. Electricity sales and purchases on a wholesale basis are conducted under the name PacifiCorp. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining facilities and services and environmental remediation. PacifiCorp's goal is to provide safe, reliable, low-cost electricity to its customers, while having an opportunity to earn at or close to its authorized rate of return. Costs prudently incurred by PacifiCorp to provide service to its customers are expected to be included as allowable costs for state ratemaking purposes.

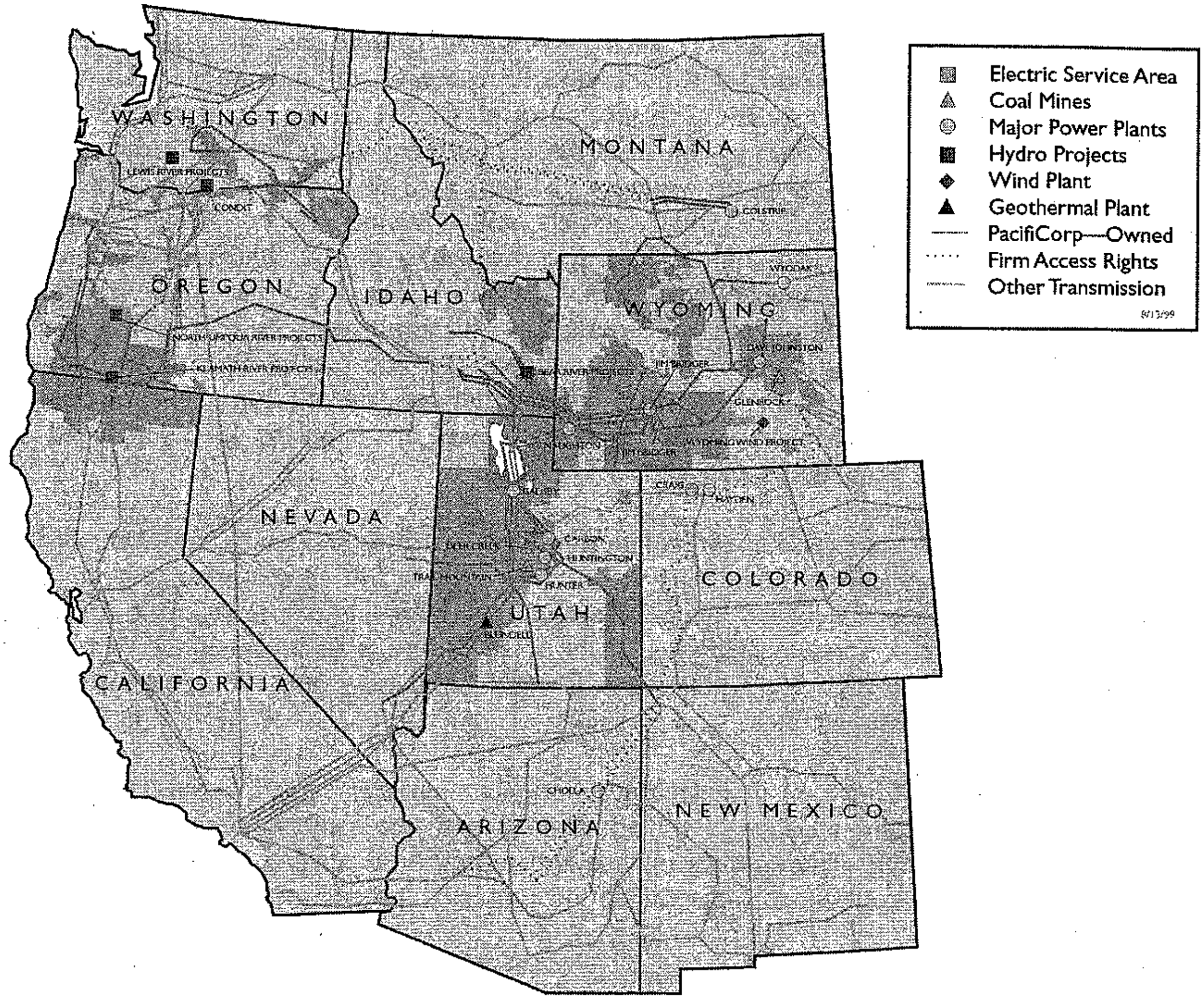
PacifiCorp is subject to comprehensive regulation by the Securities and Exchange Commission (the "SEC"), the Federal Energy Regulatory Commission (the "FERC") and other federal, state and local regulatory agencies. These agencies regulate many aspects of PacifiCorp's business, including customer rates, service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, wholesale sales and purchases, and the operation of its generation and transmission facilities.

This overview of PacifiCorp will include a description of territory served, customers and air quality strategy. In addition, because PacifiCorp is a regulated company, some regulatory issues will be discussed in detail. These topics include hydroelectric relicensing and the Multi-State Process. Finally, a description and discussion of proposed procurement activities will be presented.

SERVICE TERRITORIES

PacifiCorp serves approximately 1.6 million retail customers in a service territory aggregating about 136,000 square miles in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho and California. The combined service territory's diverse regional economy ranges from rural, agricultural and mining areas to urbanized manufacturing and government service centers. No one segment of the economy dominates the service territory, which mitigates PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, mainly consisting of Utah, Wyoming and southeast Idaho, the principal industries are manufacturing, health services, recreation and mining or extraction of metals, coal, oil, natural gas, phosphates and elemental phosphorus. In the western portion of the service territory, mainly consisting of Oregon, southeastern Washington and northern California, the principal industries are agriculture and manufacturing, with pulp and paper, lumber and wood products, food processing, high technology and primary metals being the largest industrial sectors. The following map highlights PacifiCorp's retail service territory.

Figure 2.1 – PacifiCorp Territory Map



The geographic distribution of PacifiCorp's retail electric operating revenues for the year ended March 31, 2004 was as follows: Utah, 38.5%; Oregon, 31.5%; Wyoming, 12.8%; Washington, 8.4%; Idaho, 6.3%; and California, 2.5%.

CUSTOMERS

Electricity sales and retail customers, by class of customer, for the years ending March 31, 2004, 2003 and 2002, are shown in Table 2.1.[8]

[8] The wholesale sales figures reported are net of transactions settled financially where no physical transfer of power by the settling party occurs (bookout transactions). Note that wholesale sales figures in the 2003 IRP were reported on a gross rather than net basis.

Table 2.1 – Electricity Sales and Retail Customers

	Years Ended March 31,					
Electric Operations (Thousands of MWh)	2004		2003		2002	
MWh sold						
Residential	14,460	23.3 %	13,287	21.6 %	13,395	22 %
Commercial	14,413	23.2	14,006	22.6	13,810	22.6
Industrial	19,133	30.8	19,048	30.8	19,611	32.2
Other	673	1.1	631	1	711	1.2
Total retail sales	48,679	78.4	46,972	76	47,527	78
Wholesale sales	13,407	21.6	14,873	24	13,403	22
Total MWh sold	62,086	100 %	61,845	100 %	60,930	100 %
Number of Retail Customers (Thousands)						
Residential	1,341	85.4 %	1,317	85.4 %	1,296	85.4 %
Commercial	190	12.1	186	12.1	182	12
Industrial	34	2.2	34	2.2	35	2.3
Other	5	0.3	5	0.3	4	0.3
Total	1,570	100 %	1,542	100 %	1,517	100 %
Residential Customers						
Average annual usage (kWh)	10,889		10,182		10,411	
Average annual revenue per customer	$ 749		$ 701		$ 701	
Revenue per kWh	6.9 ¢		6.9 ¢		6.7 ¢	

During the year ending March 31, 2004, no single retail customer accounted for more than 1.7% of PacifiCorp's retail electric revenues, and the 20 largest retail customers accounted for 13.0% of PacifiCorp's retail electric revenues.

For the five years to March 31, 2009, PacifiCorp is estimating average growth in retail megawatt-hour (MWh) sales in PacifiCorp's franchise service territories to be in the range of 1.5% to 2.6% annually, depending on factors such as economic conditions, number of customers, weather, conservation efforts and changes in prices.

Seasonality

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 are due to heating requirements. In the eastern portion, customer demand peaks in the summer when irrigation and air-conditioning systems are heavily used.

TRANSMISSION AND DISTRIBUTION

PacifiCorp delivers electricity through 57,464 miles of distribution lines and 15,763 miles of transmission lines. To continuously improve customer service and network safety, reliability and performance, PacifiCorp is focusing on infrastructure improvement projects in targeted areas, particularly along Utah's Wasatch Front, where there has been rapidly growing demand for electricity due to customer growth and peak load growth.

POWER AND FUEL SUPPLY

As of March 31, 2004, PacifiCorp owns, or has interests in, the following types of electricity generating plants (Table 2.2):

Table 2.2 – Types of Electricity Generating Plants

	Plants	Nameplate Rating (MW)	Net Plant Capability (MW)
Thermal			
Coal	11	6,585.80	6,107.40
Natural gas and other	5	723.80	683.00
Hydroelectric	54	1,077.30	1,164.00
Wind	1	32.60	32.60
Total	71	8,419.50	7,987.00

The following table (Table 2.3) shows the percentage of PacifiCorp's total energy requirements supplied by its generation plants during the year ending March 31, 2004.

Table 2.3 – Percentage Supplied by Generating Plants

	Year Ended March 31, 2004
Thermal	
Coal	68.4 %
Natural gas and other	4.1
Hydroelectric	5.4
Wind	0.2
TOTAL	78.1 %

PacifiCorp obtains the remainder of its energy requirements, including any changes from expectations, through short- and long-term contracts or spot market purchases described below under "Wholesale Sales and Purchased Electricity." The share of PacifiCorp's energy requirements generated by its plants will vary from year to year and is determined by factors such as planned and unplanned outages, availability and price of coal and natural gas, precipitation and snowpack levels, environmental considerations and the market price of electricity.

Coal

As of March 31, 2004, PacifiCorp had an estimated 220.1 million tons of recoverable coal reserves in mines owned or leased by PacifiCorp. The coal from these reserves and from long-term contracts will be used to support PacifiCorp's fuel strategy at its generation plants. During the year ended March 31, 2004, these mines supplied 30.4% of PacifiCorp's total coal requirements, compared to 32.7% during the year ended March 31, 2003 and 32.5% during the year ended March 31, 2002. Coal is also acquired through other long-term and short-term contracts. PacifiCorp-owned mines are located adjacent to many of its coal-fired generating plants, thus significantly reducing overall transportation costs included in fuel expense.

Natural Gas
PacifiCorp supplies its natural gas-fired generation plants through contracts of varying terms. PacifiCorp currently supplies four natural gas-fired generating plants (composed of 14 generating units) that, at full capacity, require a maximum of 229,000 MMBtu (million British thermal units) of natural gas per day.

PacifiCorp's 2003 Integrated Resource Plan identified the need for additional generation resources. Part of the requirement for additional generation resources will be met by the new Currant Creek plant and the new Lake Side plant, which are expected to begin operations in June 2005 and May 2007 respectively. PacifiCorp employs a natural gas fuel strategy which focuses on the management and mitigation of risks associated with supplying natural gas to fuel generation. This strategy applies to all of PacifiCorp's natural gas requirements which include those requirements for both Currant Creek and Lake Side. Consistent with its Long Term Natural Gas Strategy, PacifiCorp has acquired necessary natural gas transportation necessary to supply Currant Creek and is in final negotiations for transportation serving Lake Side. Additionally, PacifiCorp has purchased all of its forecasted natural gas supply needs (including supplies for Currant Creek and Lake Side) through calendar year 2006 and 80% of forecasted needs for calendar 2007.

The prospective growth of PacifiCorp's natural gas requirements points to the need for a prudent, disciplined and well-documented approach to natural gas procurement and hedging to prudently manage the costs for our customers. PacifiCorp has developed a natural gas strategy that addresses the need to hedge the commodity risk (physical availability and price), the transportation risk and the storage risk associated with its forecasted and potentially growing natural gas requirements. The natural gas strategy, combined with the prospect for increasing natural gas requirements, is expected to increase the volume and types of PacifiCorp's procurement and hedging activity and extend the term of such activities beyond calendar year 2006.

Hydroelectric
PacifiCorp's hydroelectric portfolio consists of 54 plants with a net plant capability of 1,164 MW. These plants account for approximately 14.6% of PacifiCorp's total generating capacity and provide operational benefits such as flexible generation, spinning reserves and voltage control. Hydroelectric plants are located in the following states: Utah, Oregon, Wyoming, Washington, Idaho, California and Montana.

The amount of electricity PacifiCorp is able to generate from its hydroelectric plants depends on a number of factors, primarily snowpack in the mountains upstream of its hydroelectric facilities, reservoir storage, precipitation in its watershed and resulting streamflow conditions. When these factors are favorable, PacifiCorp can generate more electricity using its hydroelectric plants. When these factors are unfavorable, PacifiCorp must increase its reliance on more expensive thermal plants and purchased electricity.

POWER AND FUEL SUPPLY

As of March 31, 2004, PacifiCorp owns, or has interests in, the following types of electricity generating plants (Table 2.2):

Table 2.2 – Types of Electricity Generating Plants

	Plants	Nameplate Rating (MW)	Net Plant Capability (MW)
Thermal			
Coal	11	6,585.80	6,107.40
Natural gas and other	5	723.80	683.00
Hydroelectric	54	1,077.30	1,164.00
Wind	1	32.60	32.60
Total	**71**	**8,419.50**	**7,987.00**

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Renewable Resources

PacifiCorp is committed to renewable energy resources as a viable, economic and environmentally prudent means of generating electricity. Wind energy can be variable and somewhat seasonal in nature. For PacifiCorp's wind resources, most strong winds occur in the winter months, and there is a reduction in the summer months.

PacifiCorp acquires wind power through a PacifiCorp-owned wind farm and various purchased electricity agreements. For the year ended March 31, 2004, PacifiCorp received 61,560 MWh from its owned wind farm. In this same period, 183,071 MWh were purchased from other wind sources. The purchased total is expected to increase in fiscal year 2005 as one of the vendor-owned wind farms was in commercial operation for only four months of the year ending March 31, 2004.

PacifiCorp has integration, storage and return agreements with Bonneville Power Administration, Eugene Water and Electric Board, Public Service Company of Colorado, and Seattle City Light. For the year ending March 31, 2004, electricity under these agreements totaled 503,196 MWh in addition to the wind energy generated or purchased for PacifiCorp's own use.

PacifiCorp owns and operates the Blundell Geothermal Plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 23 MW. Blundell is a fully renewable, zero-discharge facility. No fossil fuels are used to generate electricity; rather it is renewed and generated by heat in the ground. There is also no pollution of the atmosphere because of the absence of combustion by-products.

PacifiCorp has invested in Solar II, the world's largest solar energy plant, located in the Mojave Desert. The company has also installed panels of photovoltaic (PV) cells on three experimental rooftop locations in its service area, including The High Desert Museum in Bend, Oregon, PacifiCorp's office in Moab, Utah, and an elementary school in Green River, Wyoming.

DEMAND SIDE MANAGEMENT (DSM) PROGRAMS

Classes of DSM

DSM programs vary in their dispatchability, firmness of results, term of load reduction benefit and persistence over time. For purposes of this IRP and for communication clarity when discussing DSM, these programs are being divided into four general classes:

Class 1 DSM

Fully dispatchable resources: Load reduction only occurs when actively controlled by PacifiCorp. Once the customers agree to participate in a Class 1 DSM program, the timing and persistence of the load reduction is involuntary on their part within agreed limits and parameters. Examples include residential and commercial central air conditioner load control, irrigation load control and commercial/industrial lighting load control.

Class 2 DSM
Non-dispatchable, conservation programs: Energy and capacity savings that have been achieved through a technological improvement in appliances, equipment or structures. Savings will endure for the life of the installed system.

These types of programs provide an incentive to customers to replace existing (or to upgrade in new construction) customer-owned equipment to more efficient lighting, motors, air conditioning systems, etc. Program examples include the Energy FinAnswer, the Self-Direction Credit program, the "Cool Cash" Efficient Air Conditioner program, and the "See ya later refrigerator" program.

Class 3 DSM
Price responsive programs: Short duration (hour by hour) energy and capacity savings that are achieved through actions taken by customers voluntarily, based on a financial incentive provided by PacifiCorp with hour by hour load reduction results measured on an individual customer basis. Examples include the Energy Exchange program, interruptible/curtailable tariffs, Time Of Use (TOU) pricing and inverted block tariffs.

Load reduction endures only for the duration of the incentive offering. The load reductions observed through implementation of these programs at PacifiCorp are neither predictable, consistent or persistent.

Class 4 DSM
Conservation education: Energy and capacity reductions achieved through behavioral changes. Specific program results cannot be relied upon for planning purposes. Long-term, persistent changes will be seen in historical load growth pattern changes over time.

Examples include the Power Forward program, brochures, newsletters, billing messages, advertising and other types of public education and awareness programs that promote energy-reducing methods such as conservative thermostat settings, turning off appliances when not in use, etc.

Existing DSM Programs
PacifiCorp has been operating successful DSM programs for many years. The following is a summary of these resources by DSM Class. Appendix C in this document provides a detailed list of existing DSM programs.

Class 1 – Load Control
There are currently two programs in operation. Cool Keeper is a residential and commercial air conditioner load control program. It is building to 90 MW by FY 2007. The Idaho Irrigation Load Control program is expected to maintain at least 35 MW of load control.

Class 2 – Conservation, Physical Changes Made to Reduce Energy Use.
From 1992 through FY 2004, PacifiCorp has achieved 198 MWa of Class 2 DSM. Current efforts are achieving DSM at the rate of 24 MWa per year (PacifiCorp together with the Energy Trust of Oregon) in the service territory.

Renewable Resources

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From 1992 through FY 2004, PacifiCorp has achieved 198 MWa of Class 2 DSM. Current efforts are achieving DSM at the rate of 24 MWa per year (PacifiCorp together with the Energy Trust of Oregon) in the service territory.

Class 3 – Price Responsive Load Reduction
Currently, roughly 57% of PacifiCorp's customers are eligible for some form of voluntary price responsive tariff or program. The Energy Exchange program has identified as much as 95 MW available to be curtailed by major customers should prices rise sufficiently. There are over 15,000 customers who have chosen TOU tariffs.

Class 4 – Customer Education
Educating customers regarding their DSM opportunities is an important component of the Company's DSM resource acquisition. A variety of media are used to educate customers including, TV, radio, newspapers, bill inserts, bill messages, newsletters and personal contact. Specific firm load reduction due to education will show up in other DSM Class program results and the changes in the load forecast over time.

Table 2.4 provides a summary of the Expected DSM by Class.

Table 2.4 – Expected DSM 2005-2014 Summary

		MW at Customer Meter	MW at Generator
Class 1	Central Air Conditioner Load Control	90 MW peak	100 MW peak
	Irrigation Load Control	35 MW peak	39 MW peak
	TOTAL Class 1	125 MW peak	139 MW
Class 2	Company Programs	147 MWa	162 MWa
	ETO Plans	86 MWa	95 MWa
	TOTAL Class 2	233 MWa	257 MWa
Class 3	Energy Exchange	0-95 MW peak	0-104 MW peak
Class 4	Power Forward	0-70 MW peak	0-78 MW peak

Table 2.5 shows the expected contribution of Class 2 DSM to the PacifiCorp service territory from the Energy Trust of Oregon's April, 2004 projection. The ETO mandate ends in February, 2012.

Table 2.5 – Energy Trust of Oregon Projected DSM Achievements (MWa) at Customer Meter

CY2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
9.6	11.5	11.0	10.1	10.2	10.5	10.6	10.8	1.7	0.0

WHOLESALE SALES AND PURCHASED POWER

PacifiCorp uses its portfolio of generation assets and long-term firm purchases to meet its load obligations. In addition, PacifiCorp purchases electricity in the wholesale markets to meet its retail load obligations, long-term wholesale obligations, and energy and capacity balancing requirements. For the year ending March 31, 2004, 21.9% of PacifiCorp's energy requirements were supplied by purchased electricity under short- and long-term purchase arrangements, both as defined by the FERC. For the year ending March 31, 2003, 23.1% of PacifiCorp's energy requirements were supplied by purchased electricity under short- and long-term purchase arrangements. Based on current FY 2005 and FY 2006 projections, PacifiCorp does not expect a significant change in the amount of supply from these arrangements.

Many of PacifiCorp's purchased electricity contracts have fixed price components, and these provide some protection against price volatility. PacifiCorp enters into wholesale purchase and sale transactions to balance its supply when generation and retail loads are higher or lower than expected. Generation varies with the levels of outages, hydroelectric generation conditions and transmission constraints, and retail load varies with the weather, distribution system outages and the level of economic activity. In addition, PacifiCorp purchases electricity when it is more economical than generating at its own plants and enters into wholesale sales during periods of excess capacity.

PacifiCorp's wholesale transactions are integral to its retail business, providing for a balanced and economically hedged position and enhancing the efficient use of its generating capacity over the long-term. Historically, PacifiCorp has been able to purchase electricity from utilities in the western United States for its own requirements. PacifiCorp's transmission system connects with market hubs in the Pacific Northwest to provide access to historically low-cost hydroelectric generation and in the southwestern United States to provide access to historically 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 may sell excess electricity into the wholesale market, subject to pricing and transmission constraints.

AIR QUALITY STRATEGY

PacifiCorp Strategy for Addressing Air Quality Requirements

Air emissions from electric generating units are significant targets for air emissions regulations and utility sources are subject to a complex mix of existing and emerging air quality requirements. For large utility systems such as PacifiCorp, this reality creates the following tension:

- Ongoing pressure from the public and citizen groups to reduce emissions
- Numerous proposals for more restrictive air regulations for utility sources
- The continuing prospect of lawsuits to settle disagreements over how existing rules should be applied to utility sources
- Ongoing pressure from customers to minimize costs

PacifiCorp takes the position that the most sensible public policy solution to this dilemma is comprehensive multi-pollutant legislation for facilities. As discussed above in Chapter 1, several multi-pollutant legislative proposals have been advanced by the current Administration and members of Congress. However, it does not appear that a compromise will be found on comprehensive legislation in the near term.

Substantial developments in air quality regulation indicate that utilities would be prudent to plan for pollution control equipment now. Efforts to bring about emission reductions from utility sources will continue across the country through legislation, new regulations, enforcement actions, citizen suits and settlements. The most pressing need for reductions remains in the eastern US where many communities fail to meet health-based standards (referred to as national ambient air quality standards or NAAQS). But even in the western states where air quality is excellent, immediate concerns over power plant emissions will continue because of alleged impacts to National Parks, monuments, wilderness areas, and to sensitive ecosystems. In addition, there is a growing concern about air quality problems that could develop as the region's population continues to grow.

It is especially important for electric utility companies to plan for the future because they have a legal requirement to provide uninterrupted service to the public. Significant time and capital are needed to install pollution control equipment at electric generating units. To meet its obligations to the public in a cost effective manner, utilities must carefully plan and coordinate these efforts. Capital projects to upgrade existing or install new pollution control equipment are completed most efficiently during scheduled outages. This reduces costs associated with purchasing replacement power and can increase installation efficiency through coordination with scheduled maintenance activities.

The timely and efficient installation of pollution controls also helps avoid entanglements with legal disputes about the applicability of existing pollution control requirements at a particular source. Controls resulting from enforcement actions and litigation by their nature cannot be planned and coordinated. These disputes often become bogged down in a protracted legal process. If and when they are resolved, the installation of controls frequently occurs in compressed timeframes resulting in greater expense.

Ideally, the nature and timing of air quality requirements would be clear and specific so that owners and operators of facilities could plan investments appropriately. Commissions and customers could also be assured that investments were being made for the right reasons, at the correct level and at the right time. However, as explained above, uncertain air emissions policy results in uncertainty about the timing of emissions reduction requirements. This uncertainty leads to questions about the certainty of cost recovery for environmental improvements through the rate making process.

In the best of all worlds, utilities like PacifiCorp could move ahead with the installation of reasonable pollution controls and be confident of cost recovery. However, public utility commissions ultimately decide whether or not to allow cost recovery for utility investments in their operations. With commissions charged by their states with the duty to keep customer rates as low as possible and with the lack of clarity surrounding air policy, utilities are not assured that investments to improve air quality will be recoverable through rates. Thus, it can be difficult for utilities to attract capital and commit to those environmental investments when cost recovery is uncertain. Some states have tackled this problem through the implementation of special mechanisms to deal with environmental expenditures. Examples of these mechanisms are as follows:

- Environmental surcharges or tariff riders
- Allowance of single-item rate cases for environmental projects
- Commission cost recovery pre-approval for environmental investments
- Enactment of environmental trust financing legislation

PacifiCorp is in the process of evaluating the need and potential for appropriate pollution controls for its fleet of coal-fired units in order to ensure the following:

- Controls address existing needs and pressures for emissions reductions
- Installation is planned and implemented in a way to ensure that costs are minimized for customers
- Projects create immediate value and are consistent with likely future requirements affecting coal-fired generating units

The purpose of this effort is to develop a system-wide strategy for the installation of pollution controls that would benefit communities and minimize costs to customers.

Potential Impact

The cost of meeting present, pending and future SO_2, NO_X and Hg regulations will be substantial, with related after-tax OMAG (Operations and Maintenance, Administrative and General) and capital expenditures through 2025 ranging between $500 million Net Present Value (NPV) and $1.7 billion (NPV). The $500 million represents a scenario in which SO_2 scrubbers and low-oxides of nitrogen burners (low-NO_X burners) are installed on PacifiCorp-operated units to meet emission reduction requirements. The $1.7 billion represents the cost of SO_2 scrubbers, Selective Catalytic Reduction controls for NO_X on all system megawatts, and baghouses with activated carbon injection for mercury. The wide range in costs reflects the continued uncertainty surrounding future air emissions policy and control requirements. Costs associated with potential future CO_2 requirements are not included in this cost range.

Huntington 2 Emissions Control Project

In July 2004 PacifiCorp approved an emission control project that will update and improve SO_2, particulate, and NO_X controls on its Huntington Unit 2, a 450-megawatt coal-fired power plant located in Emery County, Utah. The total capital cost for the project is expected to be about $120 million. Construction will begin in 2005 and the project is anticipated to be operational in early 2007.

Emission improvements once the upgrades are complete will include:

- A wet-lime scrubber will reduce sulfur dioxide emissions by about 95%, or approximately 15,000 tons per year
- A Pulse Jet Fabric Filter, commonly called a bag house, will replace the present electrostatic precipitator, and will reduce particulate emissions about 80%, or approximately 1,000 tons per year
- Low- NO_X burners will reduce nitrogen oxides by about 40%, or approximately 2,500 tons per year

The addition of these emission controls are expected to reduce mercury emissions and allow Huntington Unit 2 to meet EPA's anticipated mercury regulations. This project will enable PacifiCorp to achieve the SO_2 reductions recommended by the Western Regional Air Partnership, approved by EPA and adopted by the State of Utah to address visibility at scenic areas. The low NO_X burners are consistent with existing requirements for western plants.

Customers benefit from this project through the continued availability of low-cost generation, and by the installation of these necessary controls during a planned outage which reduces replacement power costs. Postponement of the project to a later planned outage increases project costs due to vendor availability issues, the possible expiration of Utah's pollution control sales tax exemption, and reduced SO_2 emissions allowance revenues.

This series of pollution control investments address risks associated with emissions at the Huntington 2 unit and does so in a cost-effective manner by allowing installation during a planned outage at the unit. Developing federal and state air quality regulations are expected to require similar controls on other coal generating units in the PacifiCorp fleet.

REGULATORY / FEDERAL ISSUES OR MANDATES

Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) are policies that typically require a percentage of electricity delivered to come from renewable sources, such as wind, solar, biomass, geothermal, and certain forms of hydroelectricity. At the present time, seventeen states have adopted RPSs either through legislation or rulemaking. The federal government has considered RPSs, primarily in the U.S. Senate, though support has been insufficient for adoption.

Within PacifiCorp's service territory, only California has adopted an RPS. California's RPS requires investor-owned utilities to supply 20% of retail load with renewable energy by 2017. Efforts are currently underway to accelerate the target to 2010, as several utilities, including public utilities, have formally announced such a target. The mechanics of the California RPS are complex. At its core is a cost cap to be set by regulators, above which complying entities can draw upon a state fund to cover above-market costs. PacifiCorp's requirements under the California RPS are uncertain pending clarifying legislation.

The Washington legislature considered an RPS in the 2003 and 2004 sessions, and is likely to consider it again. Strong features in versions from the 2004 session included a price cap, out-of-state facility eligibility, and inclusion of renewable energy certificates ("green tags") for compliance.

Production Tax Credits

The federal production tax credit (PTC) offers 1.5 cents/kWh, adjusted for inflation, to the output of facilities fueled by certain forms of renewables. Since its inception in 1992, the PTC has only included wind and certain forms of biomass. It has technically existed through the time span from inception to the present. However, erratic Congressional action has resulted in periodic expiration of the PTC, only to have Congress "retroactively" extend the credit to cover the period of expiration. While such trends point toward assuming PTC availability in the future for analytical purposes, for commercial purposes its volatility has resulted in unfortunate "boom-bust" cycles in renewable development.

The most recent Congressional action on the PTC occurred in September and October 2004. Congress extended the PTC through December 31, 2005. Congress then expanded eligibility from wind and certain biomass sources to open-loop biomass (i.e., biomass sourced from other than plantations), geothermal, small irrigation power, solar and landfill gas facilities. However, these facilities are eligible for the credit for a five-year period only, as opposed to the ten-year period for the technologies that were previously eligible. Moreover, the credit for open-loop biomass, small irrigation power, and landfill gas facilities will be 0.9 cents/kWh (with adjustments for inflation).

Hydro Relicensing

The issues involved in relicensing hydroelectric facilities are complex. They involve numerous federal and state environmental laws and regulations, and numerous stakeholders including agencies, Indian tribes, non-governmental organizations, and local communities and governments.

Hydroelectric generation provides unique operational flexibility in addition to its generation benefits as it can be called upon to meet peak customer demands almost instantaneously. Relicensing or decommissioning of many of PacifiCorp's projects is well underway and FERC licenses or Orders are expected to be issued for the majority of the portfolio over the next 2-5 years.

FERC hydroelectric relicensing is administered within a very complex regulatory framework and is an extremely political and often controversial public process. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate for those impacts. Stakeholder consultation is conducted throughout the process. If resolution of issues cannot be reached in the licensing process, litigation often ensues which can be costly and time-consuming. There is only one alternative to relicensing, that being decommissioning. Both choices, however, can involve significant costs.

The FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other certain criteria. The FERC must find that the project is in the broad public interest which requires "equal consideration" of the impacts of the project on fish and wildlife, cultural, recreational, land-use and aesthetics, with the project's energy production benefits. However, because some of the responsible state and federal agencies have the ability to place mandatory conditions in the license, FERC is not always in a position to balance the energy and environmental equation or public interest. For example, NOAA Fisheries and the U.S. Fish and Wildlife Service have the authority to require installation of fish passage facilities (fish ladders and screens) at projects. This is the largest single capital investment that will be made in a project and can render some projects uneconomic. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other leading to potentially contrary, or additive, licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in settlement negotiations with stakeholders, the results of which are submitted to the FERC for incorporation into a new license.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and generally takes nearly 10 or more years to complete, depending on the characteristics of the project, number of stakeholders and issues that arise during the process. To date, relicensing has resulted in $54 million of accumulated process costs for which PacifiCorp is seeking or will seek recovery. As relicensing efforts continue, additional process costs are being incurred that will need to be recovered from customers. Also, new requirements contained in FERC licenses or decommissioning Orders could amount to over $2 billion over the next 30 to 50 years. Such costs include capital and O&M investments made in fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures as well as project operational changes including lost generation as a result of increased in stream flow requirements to protect fish. About 90 percent of these relicensing costs relate to PacifiCorp's three largest projects: Lewis River, Klamath River and North Umpqua.

PacifiCorp's Approach to Hydroelectric Relicensing

As noted, PacifiCorp is managing this process by pursuing negotiated settlements as part of the relicensing process. PacifiCorp believes this proactive approach, which involves meeting agency and others interests through creative solutions is the best way to achieve environmental improvement while managing costs. PacifiCorp also has reached agreements with licensing stakeholders to decommission projects where that has been the most cost-effective outcome for our customers. And, PacifiCorp has been active in efforts to reform the Federal Power Act to allow greater consideration of mitigation alternatives that deliver the same or similar environmental enhancement to agency mandates.

Multi-State Process (MSP)

In April 2002, PacifiCorp and interested parties from across PacifiCorp's service area initiated the MSP to design a mutually acceptable solution or solutions to the states' and PacifiCorp's problems arising from the current approach to operating PacifiCorp as a multi-state utility. The parties entered into the MSP primarily to develop and review regulatory cost allocation methods. They met jointly through July 2003 without reaching consensus on a single method. In September 2003, PacifiCorp filed an allocation method with most of its jurisdictions. PacifiCorp and interested parties in several states, primarily Oregon and Utah, continued active discussions. Concerns regarding several provisions of PacifiCorp's proposal were raised. These concerns led PacifiCorp to file a revised allocation protocol in May 2004.

PacifiCorp subsequently entered into stipulations with key regulatory parties in the states of Idaho, Oregon, Utah, Washington and Wyoming. The Wyoming Commission issued an oral order adopting the Revised Protocol in October. The Utah Commission issued an order adopting the Revised Protocol in December. Washington issued an order in October that establishes the Revised Protocol for reporting purposes and calls for continued discussions related to a permanent allocation methodology. Orders are expected in the near future for Oregon and Idaho.

PacifiCorp's Proposed Allocation Method

PacifiCorp is committed to designing and implementing a solution that is mutually acceptable, durable and feasible in a multi-state environment. Elements of PacifiCorp proposed method include:

New Resources

- The costs of most resources are allocated to all states based on the state's changing contribution to system demand and energy
- Costs of a new Qualifying Facility (QF) contract that exceed the costs PacifiCorp would have otherwise incurred to acquire a comparable resource are assigned to the state that approves the QF contract
- Costs of a seasonal resource are allocated to states based on each state's contribution to system demand and energy in the months in which the resource operates
- Costs associated with resources acquired pursuant to a portfolio standard in excess of the costs PacifiCorp would otherwise have incurred to acquire comparable resources are assigned to the state implementing the standard
- Costs of demand-side management programs are assigned to the local state. Benefits are reflected in the form of reduced dynamic allocation factors for other resources

Existing Resources

- A "hydro endowment" more directly assigns the costs of company-owned hydroelectric resources and, to a substantial extent, hydro-based contracts with the Mid-Columbia utilities to the former Pacific Power states
- The costs of existing QF contracts are assigned to the state that approved the QF contract to the extent that the costs exceed the embedded cost of other resources
- The costs of other existing resources are allocated to all states based on each state's contribution to system demand and energy

A Standing Committee composed of Commissioners from the various states or their appointees will continue to evaluate the impacts of load growth and other key issues.

Treatment in the IRP

While recognizable, MSP risks are particularly difficult to quantify. The IRP process seeks to develop a least cost plan for serving PacifiCorp's customers. MSP moves beyond the context of

IRP by addressing the allocation of costs among the states. Accordingly, no model adjustments or scenarios include assumptions specifically related to MSP.

RECENT PROCUREMENT ACTIVITIES

In support of the 2003 IRP plan, the company issued two competitive supply side solicitations and one comprehensive demand side RFP.

RFP 2003-A (Supply Side RFP)

RFP 2003-A was issued in June 2003 in search of resources capable of delivery beginning by the summer of 2005, the summer of 2007, and seasonally during the summers of 2004, 2005, 2006, and/or 2007. As a result of RFP 2003-A, PacifiCorp determined that the Currant Creek and the Lake Side natural gas projects were the best choices in order to meet the needs of customers beginning in the summers of 2005 and 2007 respectively.

Currant Creek is a 525 MW project that will be constructed by PacifiCorp nearby the Mona, Utah 345 kV substation. Currant Creek will be constructed in a staged fashion with 280 MW being available by the summer of 2005 and 525 MW being fully available by the summer of 2006. Lake Side is a 534 MW project that will be developed by Summit Power and constructed by Siemens-Westinghouse. Both projects will utilize combined cycle combustion turbines to convert natural gas to electricity.

RFP 2003-B (Renewables RFP)

RFP 2003-B was issued in February 2004 and solicited renewable resources that could be made available each year from 2005 through 2010. The IRP identified acquiring up to 1,400 megawatts of renewable resources over the next 10 years as part of a balanced portfolio designed to ensure safe, reliable, low-cost energy for Pacific Power and Utah Power customers. PacifiCorp may acquire up to 1,100 megawatts of economic resources through the RFP 2003-B process, which covers the first seven years of the plan. The RFP produced bids for more than 6,000 megawatts of renewable resources from dozens of proposed projects across PacifiCorp's service territory.

PacifiCorp's initial ranking of the top seven bids has been expanded to include proposals that can take advantage of the federal Production Tax Credit (PTC) recently extended by Congress and signed into law by the President. The short list contains 15 projects from 12 bidders, representing approximately 2,200 megawatts of nameplate capability.

PacifiCorp's goal was to have 100 megawatts of renewable resources on-line in Fiscal Year 2006. It is not certain at this time which projects will ultimately be able to achieve commercial operation in Fiscal Year 2006.

Next steps in the RFP 2003-B process include additional review of the short list proposals with bidders, assessing cost effectiveness of short listed proposals, and the signing of long-term power purchase contracts. PacifiCorp hopes to conclude negotiations on at least some agreements prior to the end of Fiscal Year 2005.

Demand Side RFP

The Demand-side RFP was issued in June, 2003. There were 34 proposals received from 25 Proposers. One Class 1 program (commercial and industrial lighting load control) and two Class 2 programs (residential new construction incentives and commercial re-commissioning) were found to be cost-effective. These programs are now completing the contracting and tariff filing process and are expected to be launched by early 2005. These programs will operate in Utah initially.

SUMMARY

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. In addition, DSM programs and renewable energy options are currently being implemented and potential new ones are being assessed and implemented via the RFP process.

3. RESOURCE NEEDS ASSESSMENT

INTRODUCTION

In order to develop a plan to meet the future needs of our customers, it is necessary to understand PacifiCorp's load and resource balance. The load and resource balance was analyzed by reviewing a year-by-year comparison of projected loads against the resources that are expected to comprise the long-term resource portfolio. This comparison indicated when PacifiCorp is expected to be either deficit or surplus on both capacity and energy for each year of the planning horizon. The assessment was done for the system and for each side of PacifiCorp's system (east and west). This information serves as the basis for evaluating portfolios of resource additions to meet the anticipated resource deficits.

To identify the load and resource balance, it is essential to understand the underlying assumptions that form the foundation of PacifiCorp's resource situation over the planning horizon. Therefore this chapter begins with a review of the major inputs and assumptions that form the basis of the load and resource balance. This will be followed by a detailed explanation of the load and resource balance for the 2004 IRP. Finally, observations will be presented about the resource deficits that are expected over the IRP planning horizon.

LOAD FORECAST

The long-term load forecast is one of the primary inputs in the IRP and drives the need for future resource additions. The load forecast that is used in the IRP is updated every two years and is a 20-year hourly forecast of expected loads. This forecast represents energy and demand use by customers for each load center on PacifiCorp's system. The forecast was prepared in March 2004 and is based on the latest available customer survey information, census data and economic forecasts. All historical and future load projections include the reductions associated with demand side management. A detailed description of the load forecasting methodology can be found in Appendix I.

Energy Forecast

Table 3.1 shows the historical average annual growth rate for the PacifiCorp system from calendar years 1991 through 2003. During 2001 and 2002 the United States experienced a recession and a significant terrorist event that slowed growth. Inclusion of years after 2000, i.e., recessionary years, dampens the underlying, relevant long-term trend growth that should be used for comparative purposes with the long-term trend forecast. As a result the forecasted growth rates are higher than the historical growth rates and are more reflective of the long-term trend growth. If the recessionary years are not included, the total historic growth rate is 1.8% compared to the 1.3% as shown in Table 3.1.

Table 3.1 also shows the forecasted growth rates from FY 2006 through FY 2015 in total and for each state. The 20-year long-term growth rate of this forecast is 2.1%.

Table 3.1 – Historical and Forecasted Average Growth Rates for Load

Average Annual Growth Rate	Total	OR	WA	WY	CA	UT	ID
1991-2003	1.3%	0.3%	1.4%	-1.2%	0.2%	3.5%	1.3%
2006-2015	2.1%	1.0%	1.0%	0.9%	1.6%	3.5%	0.6%

As can be seen from the forecasted average annual growth rates in Table 3.1, PacifiCorp's eastern system continues to grow faster than its western system, with average annual growth rates of 2.7% and 1.1% respectively, over the forecast horizon. There is a change in the growth rates in the east system in the later years of the forecast horizon due to a reduction of loads in the western portion of Wyoming. State specific trends are discussed in following sections.

Coincident Peak Loads

The coincident peak demand for a state is the MW hourly demand for that state during the same hour as the system peak demand. The non-coincident peak demand for a state is the maximum demand for that state. The non-coincident peak demand for a state may occur at a different hour and month than does the system peak demand. The system peak load is expected to grow from the FY 2004 peak of 8,922 MW at a faster rate than overall load due to the changing mix of appliances over time. Table 3.2 shows that for the same time period the total summer peak demand is expected to grow by 3.0%. The system peak which previously occurred in the winter prior to 1999 has switched to the summer as a result of these changes in appliance mix. This accounts for the large increase in total peak growth rates going from the historic to forecasted rates in Table 3.2. The change in seasonal peak is due to an increasing demand for summer space conditioning in the residential and commercial classes and a decreasing demand for electric-related space conditioning in the winter. This trend in space conditioning is expected to continue. Therefore, the disparity in summer and winter load growth will result in system peak demand growing faster than overall load. However, once the demand in space conditioning equipment stabilizes, the total load and system peak growth rates should equalize. Note that if the recessionary years are not included, the total historic coincident peak growth rate is 1.94% compared to the 1.88% as shown in Table 3.2.

Table 3.2 – Historical and Forecasted Coincident Peak Load Growth Rates

Average Annual Growth Rate	Total	OR	WA	WY	CA	UT	ID
1991-2003	1.88%	-0.83%	0.47%	-1.89%	-0.03%	6.22%	3.14%
2006-2015	3.00%	1.26%	1.80%	0.56%	2.35%	4.58%	2.28%

Again, PacifiCorp's eastern system peak is expected to continue growing faster than its western system peak, with average annual growth rates of 3.8% and 1.5% respectively over the forecast horizon. This is similar to historical growth patterns as Table 3.2 reflects. East system peak growth during this time has been faster than west system peak growth. Of course, peak growth is somewhat masked in Table 3.2 due to the peak shifting from winter months to summer months.

Table 3.3 shows the average annual coincident peak growth occurring in the summer months for 1991 through 2003 since it is expected that the system is to remain summer peaking. This shows that some of what appears to be a decrease in peak load in many states is due to the shift from winter to summer and that growth in peak is truly occurring. But it also shows that faster growth continued to occur in the eastern portion of the system relative to the west. Eastern average historical growth has been 3.4%, while the western portion of the system grew at 2.0% on average. This pattern is expected to continue as discussed previously. Note that if the recessionary years are not included, the total historic summer coincident peak growth rate is 2.84% compared to the 2.40% as shown in Table 3.3.

Table 3.3 – Historical Coincident Peak Load - Summer

Average Annual Growth Rate	Total	OR	WA	WY	CA	UT	ID
1991-2003	2.40%	1.40%	2.38%	-0.75%	1.03%	5.33%	-0.21%

Historical and forecasted loads, state coincident peak demands, and state non-coincident peak demands are provided in Appendix I.

Class 2 DSM

Identified and budgeted Class 2 DSM programs have been included in the load forecast as a decrement to the load. By FY 2015, there are 257 MWa (at generator) of Class 2 resources in the forecast. This savings includes 95 MWa (at generator) to be implemented by the Energy Trust of Oregon within PacifiCorp's service territory. Table 3.4 shows average program savings and coincident peak savings by year. In FY 2015, these Class 2 programs reduce peak system load from what it otherwise would have been by 2.7%. Additional program specific details are included in Appendix C.

Table 3.4 – Class 2 DSM Included in the System Load Forecast (measured at generator)

MWa	FY 06	FY 07	FY 08	FY 09	FY 10	FY 11	FY 12	FY 13	FY 14	FY 15
PacifiCorp	32	52	72	89	105	119	134	149	162	162
Energy Trust of Oregon	23	35	46	57	69	81	92	95	95	95
TOTAL (MWa)	**55**	**87**	**118**	**146**	**174**	**200**	**226**	**244**	**257**	**257**
Peak Reduction (MW)	**58**	**99**	**138**	**176**	**210**	**240**	**269**	**300**	**322**	**323**

State Summaries

Oregon

Table 3.5 summarizes Oregon state forecasted sales growth compared with history by customer class.

Table 3.5 – Historical and Forecasted Sales Growth in Oregon

	Residential	Commercial	Industrial	Irrigation	Other	Total
2003 GWh	5,408	4,708	3,016	229	48	13,227
1983-03	1.1%	2.8%	-0.4%	-0.2%	0.6%	1.2%
2006-15	1.1%	0.9%	1.2%	0.8%	1.1%	1.0%

The residential forecast of sales is expected to have a slightly faster growth than experienced historically. Population growth is expected to continue in the service area driving some of this growth, while usage per customer in the residential class is also growing slightly. Home size continues to increase resulting in an increased general use per customer. Summer usage is increasing from air conditioning additions. However, these are being somewhat offset by declining electric space heating saturations and appliance efficiency gains.

Forecasted commercial class sales are projected to grow slightly slower over the forecast horizon compared to historical periods. Usage per customer is projected to decline due to increased equipment efficiency offsetting increases in the saturation of air conditioning.

Industrial class sales are projected to grow faster over the forecast horizon compared to historical periods. In the latter years of this historical period two large industrial customers chose to leave PacifiCorp's system. This, coupled with declines over the decade in the Lumber & Wood industries, resulted in an overall decline in sales to this class. Over the forecast horizon, continuing growth is expected in food processing industries, specialty metals manufacturing industries, and niche lumber and wood businesses, along with continued diversification in the manufacturing base in the state.

The factors influencing the forecasted sales growth rates are also influencing the forecasted peak demand growth rates.

Washington

Table 3.6 summarizes Washington state forecasted sales growth compared with history by customer class.

Table 3.6 – Historical and Forecasted Sales Growth in Washington

	Residential	Commercial	Industrial	Irrigation	Other	Total
2003 GWh	1,564	1,364	1,047	159	11	4,145
1983-03	1.2%	2.8%	2.8%	1.1%	1.2%	2.0%
2006-15	1.4%	-0.7%	2.5%	0.4%	0.0%	1.0%

The growth in residential class sales is due to continuing population growth in this part of PacifiCorp's service area. There have not been significant changes in conditions in the state to alter the usage per customer over time.

The continuing population growth also affects the commercial sector. However, the growth in sales for this customer class is being somewhat offset from equipment efficiency gains over the forecast horizon.

The industrial class is projected to grow at nearly the historical rate. Industrial production is projected to continue growing in the food, lumber, and paper industries.

California

Table 3.7 summarizes California state forecasted sales growth compared with historical growth by customer class.

Table 3.7 – Historical and Forecasted Sales Growth in California

	Residential	Commercial	Industrial	Irrigation	Other	Total
2003 GWh	386	286	67	92	3	835
1983-03	0.8%	2.7%	-0.9%	0.5%	0.6%	1.1%
2006-15	1.9%	2.2%	-0.6%	0.2%	1.0%	1.6%

The faster rate of growth in residential class sales is driven, in part, by the continuing growth in population in this part of PacifiCorp's service area. Usage per customer in the residential class is also growing slightly. Home sizes continue to increase, resulting in more growth in use per customer. Summer electrical usage increases from air conditioning additions are being somewhat offset by declining electric space heating saturations and appliance efficiency gains.

The continuing population growth also affects sales in the commercial sector. Additionally there is a general trend in construction with new construction having larger square feet per building. However, this growth is being offset by equipment efficiency gains over the forecast horizon.

Declines over the decade in the Lumber & Wood industries production resulted in an overall decline in the industrial sales. However, there are indications that this trend has ended and growth in other businesses are expected to continue.

Utah

Table 3.8 summarizes Utah state forecasted sales growth compared with history by customer class.

Table 3.8 – Historical and Forecasted Sales Growth in Utah

	Residential	Commercial	Industrial	Irrigation	Other	Total
2003 GWh	5,408	6,362	6,672	198	564	19204
1983-03	3.3%	4.9%	2.6%	3.9%	0.4%	3.4%
2006-15	3.5%	4.6%	2.3%	0.3%	1.8%	3.5%

Utah continues to see faster population growth than many of the surrounding states. During the historical period, Utah experienced rapid population growth with a high rate of immigration from surrounding states. However, the rate of population growth is expected to be lower in the coming decade as migration into the state slows. Use per customer in the residential class should continue at current levels for the forecast horizon. One of the reasons for the high usage per customer is that newer homes are assumed to be larger. In addition, it is assumed that air conditioning saturation rates for single family and manufactured houses will continue to grow.

Relatively high growth in the commercial class will continue from customer growth. Usage per customer is projected to increase due to new construction having larger square feet per building. However, this growth is being offset from equipment efficiency gains over the forecast horizon.

The industrial class has been experiencing significant industrial diversification in the state and will continue to cause sales growth in the sector. Utah has a strategic location in the western half of the United States which provides easy access into many regional markets, which serves as a positive influence on growth. The industrial base has become more linked to the region and less dependent on the natural resource base within the state. This provides a strong foundation for continued growth into the future.

The peak demand for the state of Utah is expected to have a high growth rate during the forecast period. This result is due to several factors: first, newer residential structures are assumed to be larger; second, the air conditioning saturation rates in the state continue to increase in the residential and commercial sectors; and third, newly constructed commercial structures are assumed to be larger than during historical periods.

Idaho

Table 3.9 summarizes Idaho state forecasted sales growth compared with history by customer class.

Table 3.9 – Historical and Forecasted Sales Growth in Idaho

	Residential	Commercial	Industrial	Irrigation	Other	Total
2003 GWh	586	367	1,652	673	2	3,280
1983-03	0.9%	4.3%	2.3%	3.6%	1.2%	2.4%
2006-15	0.7%	2.1%	0.1%	0.5%	-0.8%	0.6%

The growth of sales in the residential class is less than historic levels but still strong. This is due to continuing population growth in this part of PacifiCorp's service area. And use per customer should continue at current high levels for the forecast horizon. One contributing factor to the increased usage is that newer homes are assumed to be larger. It is also assumed that air conditioning saturation rates will continue to be increasing during the forecast horizon.

The growth rate for commercial class sales is less than historic levels but will continue to be strong due to customer growth. Usage per customer is projected to increase, influenced in part by new construction at the Brigham Young University at Idaho campus. However, this growth is being offset from equipment efficiency gains over the forecast horizon.

Industrial sales are assumed to be near maximum levels of production and remain there during the forecast horizon.

Wyoming
Table 3.10 summarizes Wyoming state forecasted sales growth compared with history by customer class.

Table 3.10 – Historical and Forecasted sales growth in Wyoming

	Residential	Commercial	Industrial	Irrigation	Other	Total
2003 GWh	940	1,236	5,440	16	15	7,647
1983-03	1.1%	2.3%	1.5%	1.6%	-2.8%	1.5%
2006-15	0.6%	0.9%	0.9%	-0.7%	1.4%	0.8%

The residential sales forecast is expected to continue growing at nearly historical rates. Population growth is expected to continue in the service area causing some of the growth. However this growth is expected to slow somewhat in the future. Usage per customer in the residential class is growing slightly. Home sizes continue to increase, resulting in increased general use per customer. Increasing air conditioning saturations are resulting in more use per customer during the summer months.

Commercial sales are projected to grow slightly slower over the forecast horizon compared to historical periods. Usage per customer is projected to decline for the forecast period due to increased equipment efficiency.

A major change in the Wyoming sales forecast occurs in the industrial sales sector. Industrial growth in eastern Wyoming is expected to be similar to the long-term historical trend growth. However, in western Wyoming, the natural gas fields are expected to reach the end of production and the loads in this part of the state to drop from historical levels.

RESOURCE SITUATION

To compute the resource side of the load and resource balance, it is necessary to understand the assumptions regarding the resources that comprise PacifiCorp's resource base. For the purposes of clarity, the 2004 IRP will define the term Existing Resources and introduce a separate category of base resources called Planned Resources. Planned Resources are included in the load and resource balance because they reflect decisions and/or acquisition processes that can be predicted with some degree of confidence. PacifiCorp is firmly committed to acquiring these Planned Resources and either is in the process of procuring the resource(s) (e.g. RFP 2004-B), or there is a solidly established historical pattern associated with the resource acquisition. PacifiCorp believes that delineating these two resource categories more accurately portrays the planning status of certain near-term resources.

This section will briefly describe these two resources groups as well as the resource assumptions that affect the load and resource balance.

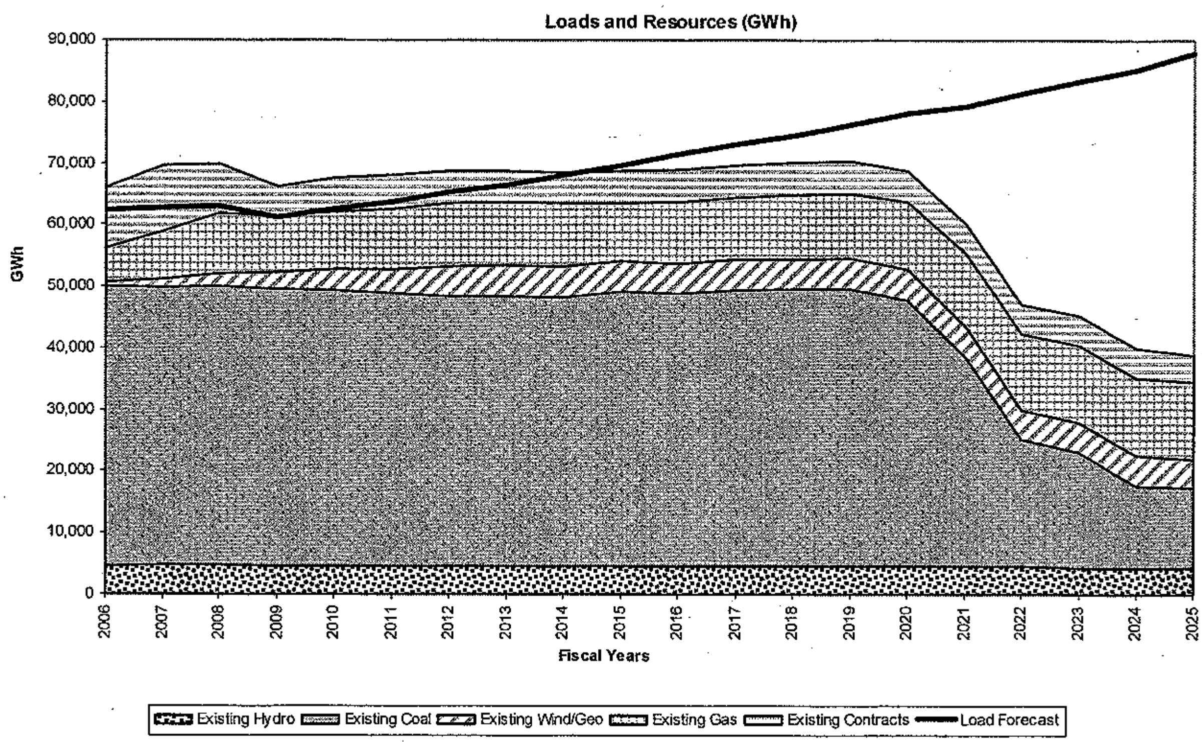
Existing Resources
The first resource group in the resource base data is referred to as Existing Resources. These are defined as resources currently in operation or for which procurement contracts have been signed.

This definition includes the resources discussed in Chapter 2, which during the year ending March 31, 2004, includes PacifiCorp ownership or interests in generating plants with an aggregate plant net capability of 7,987 MW. With its present generating facilities, below-average water conditions, approximately 5.4% of PacifiCorp's energy requirements are supplied by its hydroelectric plants, 72.5% by its thermal plants, 0.1% by its wind resources and 22% obtained through long-term purchase contracts, exchange and other purchase arrangements.

The above definition of Existing Resources also includes two natural gas-fired, thermal plants which were procured through a competitive bid process and are in the process of being constructed. These plants are the Currant Creek 525 MW combined cycle plant scheduled to begin full operations in April of 2006 and the Lake Side 534 MW combined cycle plant scheduled to be online in June of 2007. Furthermore, Existing Resources includes all contracts signed as of May 1, 2004 (e.g. Deseret).

Figure 3.1 shows the projected annual energy delivered by various resource types under normal conditions over the 2004 IRP planning horizon (FY 2006-2025) as compared to projected loads. It shows the expected contributions of PacifiCorp's existing hydro, coal, renewable and gas resources as well as energy delivered from existing contracts.

Figure 3.1 – PacifiCorp Resource Composition



Contract Expirations

Contract expirations over the IRP planning horizon lower the available existing resources (see Appendix C for a complete list of contracts). However, three significant contracts may expire within the first ten years of the IRP planning horizon (FY 2006-2015). This would have a considerable impact on the load & resource balance, and thus the resource deficit to be filled in that timeframe. These contracts are as follows:

- The West Valley Lease has been extended through May 31, 2008. Beginning on June 1, 2008 it is assumed for planning purposes that it will not be extended.
- The 400 MW power purchase agreement with TransAlta Energy Marketing expires in FY 2008.
- The 575 MW BPA peaking contract expires in FY 2012.

Plant Lives

The PacifiCorp system is comprised of numerous existing thermal plants which are at a variety of plant ages and expected retirement dates. Thermal plant retirement dates are summarized in Table 3.11. It should be pointed out that two thermal plants, Carbon and Gadsby, had their economic lives extended since the 2003 IRP. Carbon was extended from calendar year 2010 to 2020. Gadsby was extended from 2007 to 2017. This was based on a cost effectiveness study subsequent to the 2002 Depreciation Study which indicated that, based on current asset condition and environmental regulations, these two plants should have their economic lives extended. There are no significant retirements planned in the Action Plan horizon (2-4 years). Refer to Appendix C for a complete list of currently estimated thermal plant retirement dates.

Table 3.11 – Thermal Plant Retirement Schedule

Plant	Calendar Year
Blundell	2021
Carbon	2020
Cholla	2025
Colstrip	2029
Craig	2024
Dave Johnston	2020
Gadsby	2017
Gadsby Peakers	2027
Hayden	2024
Hermiston	2031
Hunter	2025
Huntington	2019
Jim Bridger	2020
Little Mountain	2006
Naughton	2022
Wyodak	2022
Plant lives are currently being reviewed for compliance with future environmental regulations.	

Planned Resources

The second resource group in the resource base data is referred to as Planned Resources. These are defined as resources that PacifiCorp has firmly decided to pursue and is taking actions to acquire. They include the 1,400 MW of RFP wind from the 2003 IRP, up to 1,200 MW of Front Office Transactions and 100 MW of Utah Qualifying Facility contracts.

RFP Wind

PacifiCorp's January 2003 IRP identified 1,400 MW of renewable resources as part of the least cost portfolio of resources. The addition of wind power to the resource portfolio proved to be beneficial to overall system operations by reducing the 20-year PVRR through reductions in system emissions and total fuel costs. Portfolios with wind power were less susceptible to highly variable fuel costs in the risk analysis.

The amount of renewable resources added to the portfolio has been validated by both the results from the Renewables RFP and by an additional modeling effort using the Capacity Expansion Model. See Appendix J for a description of this modeling project and other renewables assumptions. For the 2004 IRP, a 20% planning credit was applied to wind resources. Therefore, 280 of the 1,400 MW will contribute towards meeting the planning margin requirement.

PacifiCorp concludes that since the Company is committed to continuing the pursuit of renewable generation as a viable solution to meeting customer demand, it is reasonable and prudent to assume that 1,400 MW of renewable resources should be included as a Planned Resource. PacifiCorp will continue to review the assumption in future IRPs as more information regarding integration costs, impacts on system operations, and the ability to successfully acquire these resources becomes available.

Front Office Transactions

The Front Office Transaction targets included as Planned Resources are based on historical operational data and PacifiCorp's forward market view. These shorter-term, historically-based resources are intended to bridge the gap between reliance on spot market activity and long-term build-or-buy commitments in order to balance the system. Since they are part of the routine system balancing strategy and are based on historical operational data, they are appropriate for inclusion as Planned Resources.

Front Office Transactions are usually standard products, such as Heavy Load Hour (HLH), Light Load Hour (LLH), and/or daily HLH call options (the right to buy or "call" energy at a "strike" price) and typically rely on standard enabling agreements as a contracting vehicle. In the IRP, it is assumed that Front Office Transactions will consist of the standard products described above. The prices of Front Office Transactions are determined at the time of the transaction, usually via a third party broker and based on the view of each respective party regarding the then-current forward market price for power. An optimal mix of these purchases would include a range in terms for these transactions.

Solicitations for Front Office Transactions can be made years, quarters or months in advance. Annual transactions can be available up to as much as three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

The Front Office Transactions used as a Planned Resource in the 2004 IRP are fundamentally different from Structured contracts. Structured contracts tend to be complex, non-standard, highly negotiated agreements tailored to all parties involved. A Structured contract may have a number of pricing components including a "fixed" component, such as a demand or capacity charge, and a variable component, which may vary with index or pricing tier or both. However, this does not preclude a Front Office Transaction from having a complex pricing structure or a Structured contract from having a simple pricing structure. One example of a Structured contract is the TransAlta contract.

As a base planning assumption, 1,200 MW of Front Office Transactions were assumed based on past experience with products and with delivery points. These amounts were modeled as Planned Resources under the criteria described earlier in this chapter, and were incorporated directly into the capacity charts that will be discussed in the next section. As with other Front Office Transactions, absent a Power Cost Adjustment Mechanism, these transactions would be reviewed during the process of a rate case. A more detailed description of these Front Office Transactions can be found in Appendix C.

Qualifying Facilities (QFs)
The Qualifying Facility contracts included as Planned Resources were being negotiated during the IRP analysis. PacifiCorp just recently executed contracts with Kennecott, US Magnesium and Tesoro. The Desert Power contract was included as an Existing Resource. Because the process to acquire these resources was in place at the time of the IRP process, and there was a high level of confidence and consensus that the acquisitions would be successful, they were included as Planned Resources.

The IRP assumed that these resources would deliver approximately 100 MW to northern Utah and would be derived from a combination of new QFs or CHPs (like those described above) that are proposed over the next ten years, and additional QFs procured under the current Utah stipulated cap.

PLANNING MARGIN

Planning margin is the amount of resources above the peak system obligation necessary to reliably meet load. The planning margin is intended to provide sufficient future resources to meet requirements in the event of unplanned outages, meet WECC operating reserve requirements and regulating margin (load following), as well as respond to unanticipated levels of demand growth and weather-related events that vary from normal.

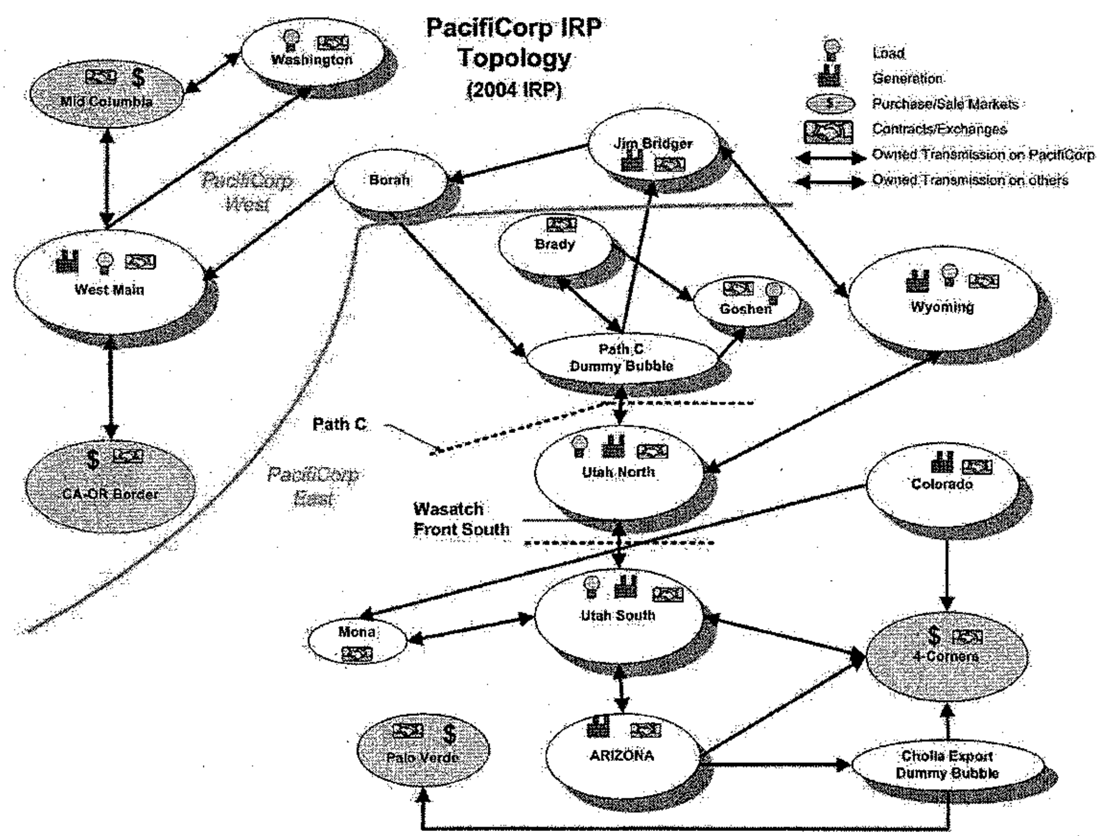
Most Regional Planning Councils across the country have set planning margin and reliability targets. WECC and SERC are the only Councils without either specified resource adequacy criteria or planning reserve margin. The most common resource adequacy criteria are the 1-in-10 year Loss of Load Probability (LOLP) or 1-in-10 Loss of Load Expectation (LOLE), which are seen as industry standard reliability thresholds. Although there are multiple regional efforts underway to define resource adequacy within WECC, utilities must currently plan to meet a level of adequacy specific to their system. PacifiCorp's neighboring utilities have defined their planning margin levels within their IRPs ranging from 12% to 17%.

For the 2004 IRP, PacifiCorp worked with Henwood Energy Services (currently Global Energy Decisions, LLC) to produce a planning margin study for the PacifiCorp system that included an LOLP analysis. The study looked at system reliability over a range of planning margins. Henwood conducted an LOLP analysis in line with the methodology used by several Regional Planning Councils across the country to determine their resource adequacy criteria. The study results showed that an 18% planning reserve margin on the system peak obligation hour provided a 1 in 10 LOLP for the system. Although a 1 in 10 year LOLP is a commonly used reliability standard, the optimum balance between cost of expected unserved energy (EUE) and additional capital investment needed to reduce EUE lies at the 2 in 10 year LOLP or 15% planning margin reserve level for the system. Therefore PacifiCorp concluded that a 15% planning margin level ensured adequate resources will be procured to meet load requirements with a high level of reliability, avoiding physical short exposure to markets, and providing for safe, reliable, low cost energy for the consumer. Refer to Appendix N for details related to the planning margin study.

PACIFICORP SYSTEM TOPOLOGY

The fundamental assumption underlying the load and resource balance is the model topology. Shown in Figure 3.2, this topology was constructed to accurately depict the PacifiCorp system with a moderate level of detail.

Figure 3.2 – PacifiCorp System Topology



This topology consists of 18 bubbles which are designed to describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Bubbles are linked by firm transmission paths. The development of this topology involved defining the loads associated with each bubble, the existing resources located in each bubble, the characteristics of each resource, and transfer capability of the links between the bubbles.

PacifiCorp's service territory is part of a highly interconnected transmission grid in the WECC and adjoined to multiple external markets. These markets serve both as energy sources and receipts of energy, at differing times, and at market determined prices. PacifiCorp relies on these markets to provide physical balancing. Additionally, interaction with these markets allows for a more accurate reflection of marginal operating costs because plant operations are based on incremental cost decisions. Market activity is a necessary and significant part of our portfolio costs and revenues. In order to model the interaction between the PacifiCorp system and the WECC markets, the topology captures interactions at the following trading points:

- Mid-Columbia (Mid-C)
- California/Oregon Border (COB)
- Four Corners (FC)
- Palo Verde (PV)

Firm transmission rights to the markets serve as PacifiCorp's primary constraint to market size. This is a conservative approach because it does not take into account non-firm transmission or opportunities to make additional sales to, or purchases from, the market.

LOAD AND RESOURCE BALANCE

The difference between the load forecast plus sales and the existing and planned PacifiCorp resources define the shortfall, or gap, in supply. This section presents the load and resource balance for the PacifiCorp system, as well as for each control area.

Capacity Charts

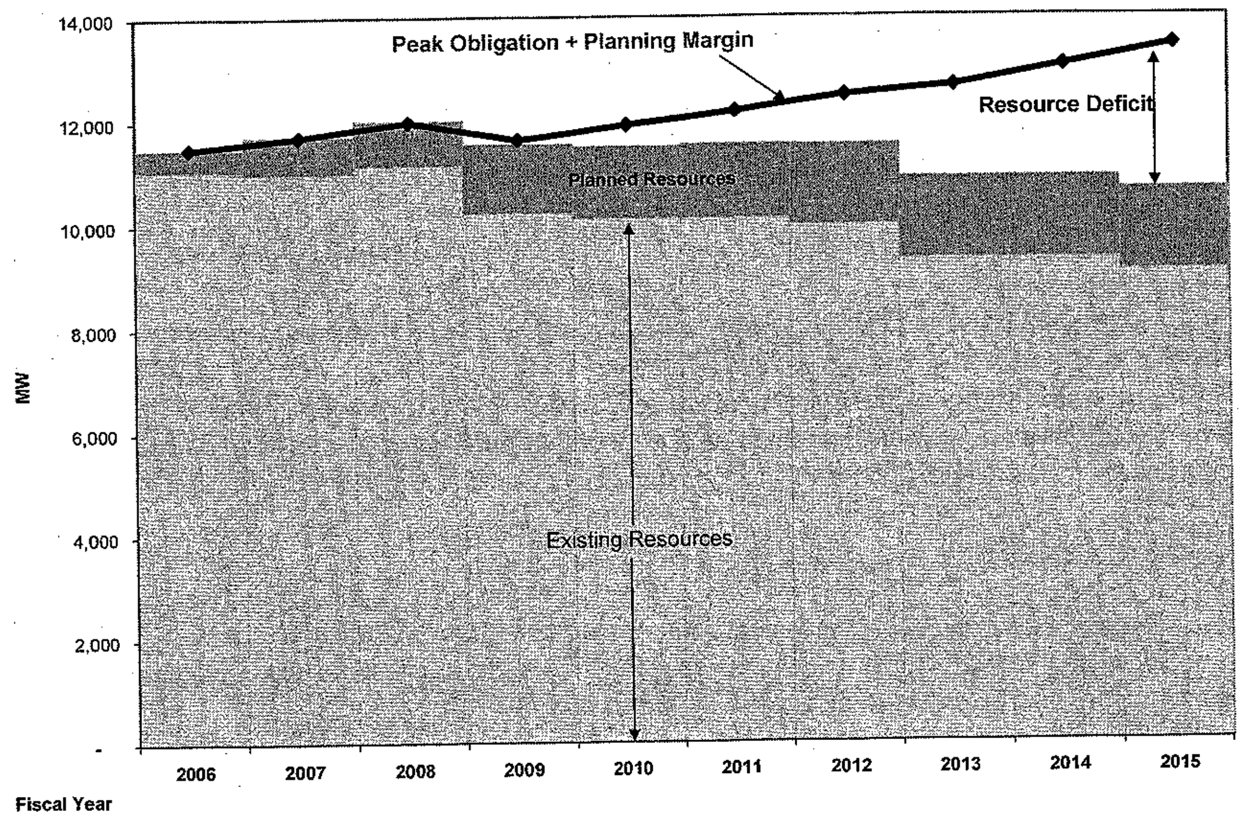
Capacity Charts show the peak obligation (load plus sales) plus the planning margin requirement as compared to the available resources for the peak load hour. They were constructed by determining the system coincident peak hour for each of the first ten years of the planning horizon (FY 2006-2015), and determining the available resources for those hours. Existing resources are computed as follows:

$$\textit{Existing Resources} = \textit{Thermal} + \textit{Hydro} + \textit{Purchases} + \textit{Interruptible} + \textit{Class 1 DSM}$$

Thermal and Interruptible resources are measured according to maximum capacity. Hydro, Purchases and Class 1 DSM are measured by model dispatch. The peak obligation is equal to load plus sales. All of the charts assume a coincident peak planning margin of 15%. The Planned Resources which includes RFP wind, Front Office Transactions and some QF contracts are shown above the Existing Resources at the top of each chart. The gap between the peak obligation and PacifiCorp's total available resources is the annual capacity deficit.

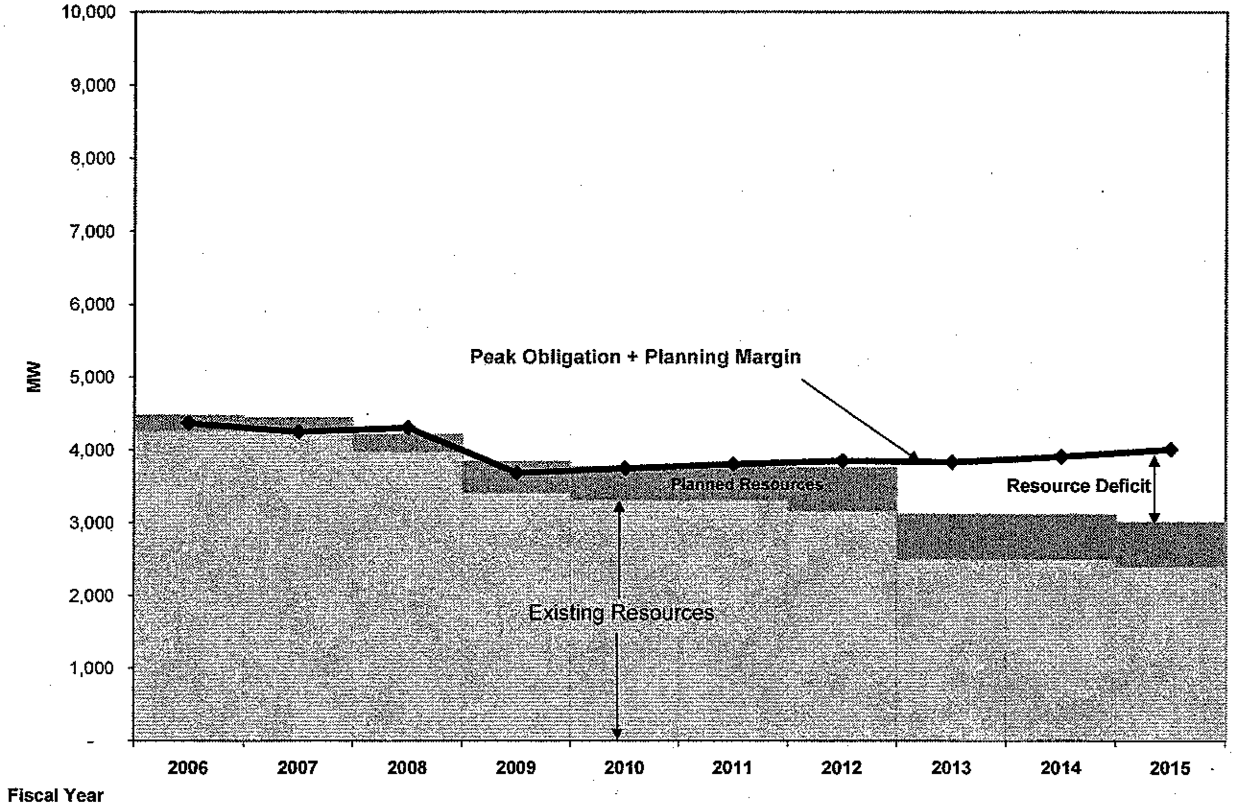
Figures 3.3 through 3.5 present the various capacity charts developed for the Load & Resource Balance. In the System and West Capacity Charts there are a few noticeable declines in resources and loads in the 10-year period mostly caused by the expiration of existing contracts. For example in FY 2008 and FY 2012, two large contracts expire – the TransAlta purchase contract and the BPA Peaking Contract, respectively. The expiration of the Clark County Load Service contract causes the drop in capacity and obligation in FY 2009.

Figure 3.3 – System Coincident Peak Capacity Chart



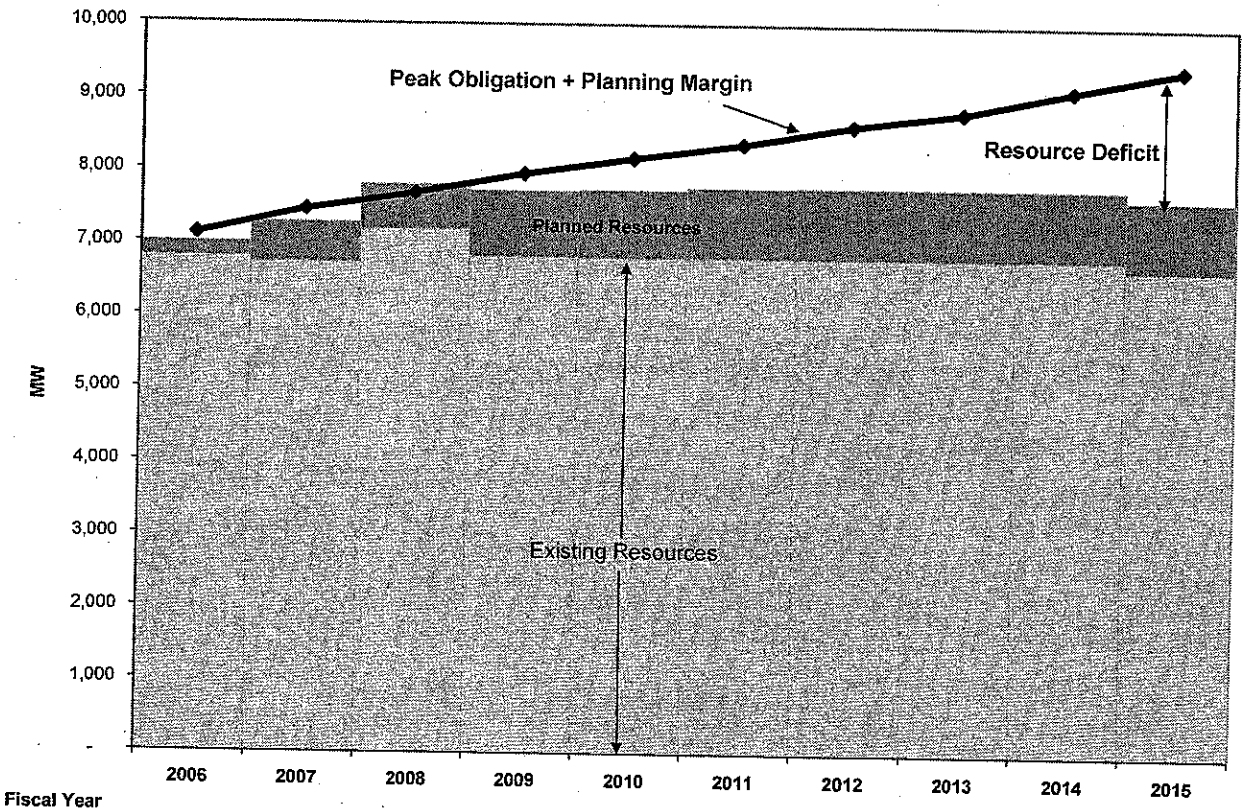
Resources	11,484	11,714	12,013	11,566	11,526	11,546	11,537	10,897	10,895	10,657
Obligation+15%	11,485	11,701	11,988	11,639	11,916	12,177	12,478	12,650	13,035	13,434

Figure 3.4 – West Coincident Peak Capacity Chart



Resources	4,485	4,445	4,216	3,848	3,793	3,772	3,761	3,120	3,117	3,013
Obligation+15%	4,368	4,248	4,306	3,686	3,746	3,805	3,850	3,835	3,910	4,010

Figure 3.5 – East Coincident Peak Capacity Chart



Resources	6,999	7,269	7,797	7,718	7,733	7,774	7,776	7,777	7,778	7,644
Obligation+15%	7,117	7,453	7,682	7,953	8,171	8,372	8,627	8,815	9,125	9,424

The increase in existing resources in FY 2008 is due to the startup of the Lake Side project. The decrease in capacity in FY 2009 is caused by the assumed expiration of the West Valley Lease.

Energy Curves

Figures 3.6 and 3.7 represent the energy curves for each side of PacifiCorp's system. These curves show the net position by month for On-Peak and Off-Peak hours for each Control Area. The On-Peak hours are weekdays and Saturdays, hour ending 7:00 am to 10:00 pm; Off-Peak hours are all other hours. The net position is resources minus obligation and includes average monthly outages and the WECC reserve requirement. Results are shown after area transfers.

Figure 3.6 – West Energy Curves

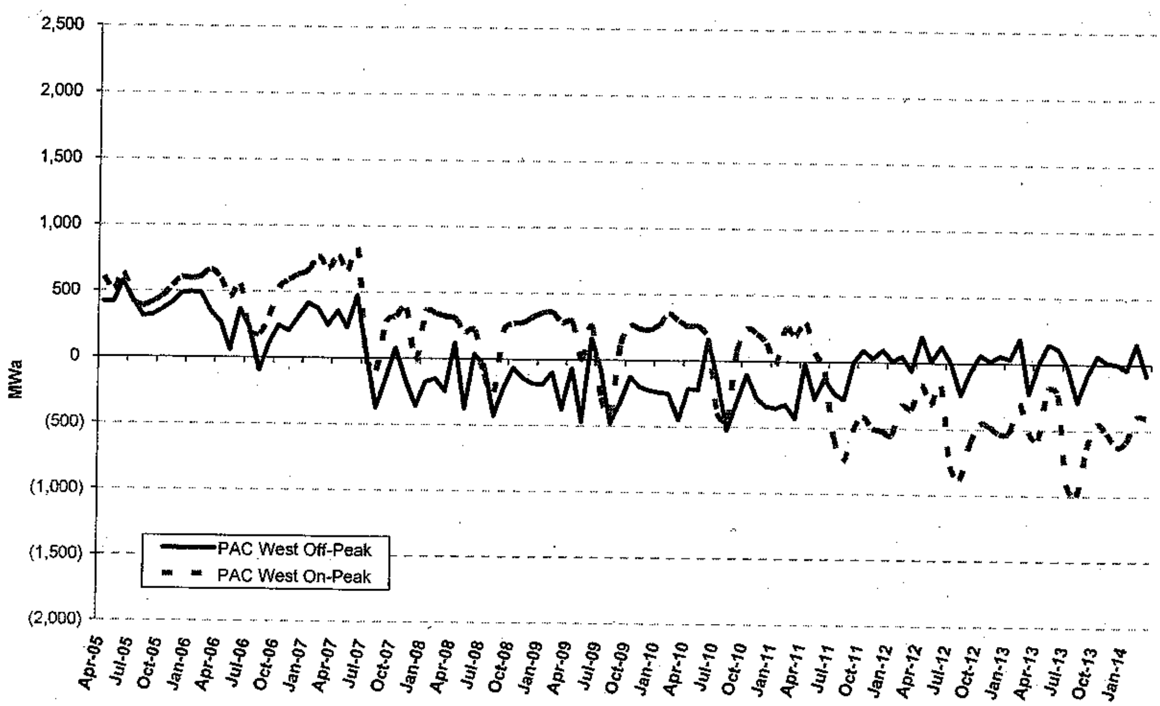
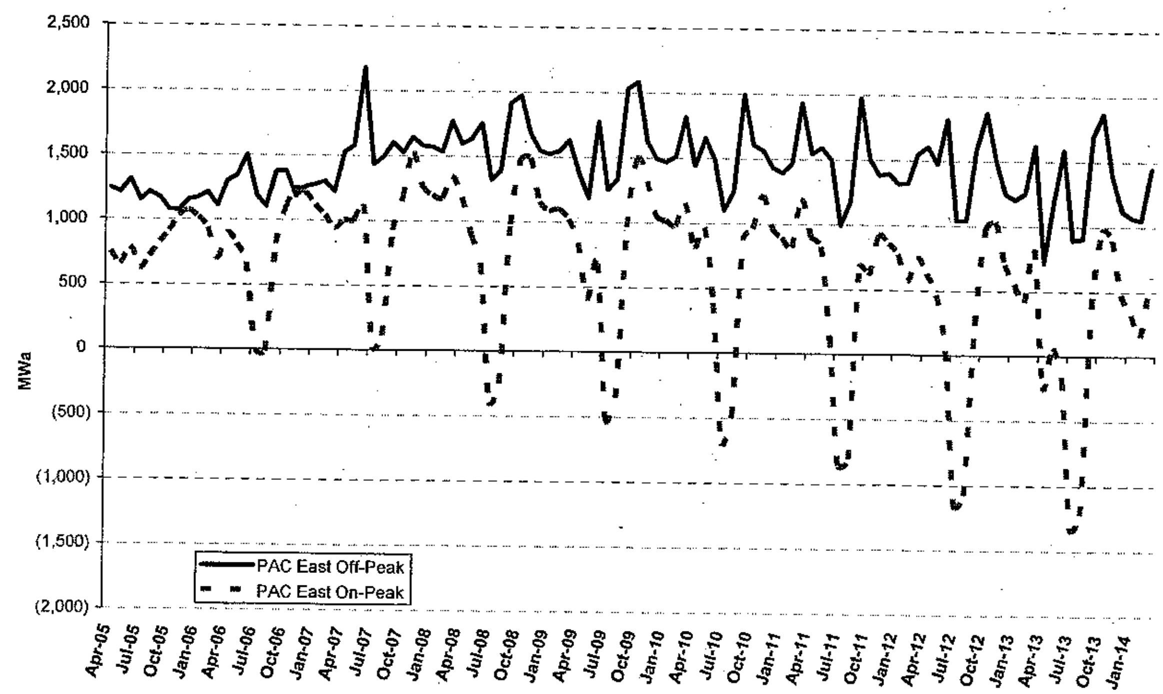


Figure 3.7 – East Energy Curves



Load and Resource Balance Observations

The PacifiCorp system is capacity sufficient until FY 2009. Beginning in FY 2009, the system becomes capacity deficit and the deficit steadily grows to approximately 2,800 MW by FY 2015.

The western side of PacifiCorp's system is capacity sufficient until FY 2011. A capacity deficit begins in FY 2012 and grows to approximately 1,000 MW in FY 2015. The western side of the system is energy short in the off-peak period until the expiration of the BPA Peaking contract in FY 2012, when it becomes short both on and off-peak.

The eastern side of PacifiCorp's system is capacity deficit beginning in FY 2009 and steadily grows to a deficit of about 1,800 MW by FY 2015. The off-peak hours are energy long for 10 years without any resource additions. The eastern side of the system is short on-peak during the summer months beginning in the summer of FY 2009.

CONCLUSION

The load and resource balance is used to determine the resource deficits, or gaps, that are expected to occur over the IRP planning horizon. The major inputs and assumptions used in the IRP affect the determination of the need for future resources. The review of the load and resource balance indicates that there is a need for approximately 2,800 MW of resource additions by FY 2015. The majority of the additions are needed on the eastern portion of the PacifiCorp system beginning in FY 2009.

9. ACTION PLAN

The IRP is intended to provide guidance and rationale for PacifiCorp's resource procurement over the next few years. A successful IRP will result in "acknowledgement" by the states indicating no significant disagreement with, and a large degree of support for, the Action Plan. How each Commission will treat a favorable acknowledgement of an IRP Action Plan in subsequent rate cases may vary.[30]

The IRP is not only a regulatory requirement but is also the primary driver for PacifiCorp's business planning. PacifiCorp's shareholders must and will take into account this IRP and subsequent governmental and public responses when making future 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. Additionally, and among other key indicators, credit rating agencies rely on the same anticipation of cost recovery when assigning credit ratings. It is also true that credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process.

This chapter summarizes the conclusions of our analysis and provides details regarding the steps that PacifiCorp anticipates taking to implement the IRP Action Plan.

PORTFOLIO SELECTION

PacifiCorp's current position (Chapter 3) reveals a substantial need for new resources. This "gap" analysis also outlines how the two portions of the system, west and 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 results of the analysis (Chapter 8) confirm that Portfolio E with DSM is the least-cost, risk informed portfolio to fill PacifiCorp's long-term resource needs based on forecasted customer demand.

Table 9.1 is a summary of the total MW, timing and proxy cost associated with specific resources contained in the Preferred Portfolio. A more comprehensive summary of this portfolio can be found in Chapter 8. In addition to the resources contained in the Preferred Portfolio, the Action Plan addresses the continuing need to pursue cost-effective renewable generation included in the Planned Resources as well as additional Class 2 DSM programs aligned with PacifiCorp's long-term DSM strategy.

[30] 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 proceedings. Oregon has suggested the Action Plan be designed to allow Oregon to acknowledge specific findings of fact. See Appendix K for a summary of each State's planning requirements.

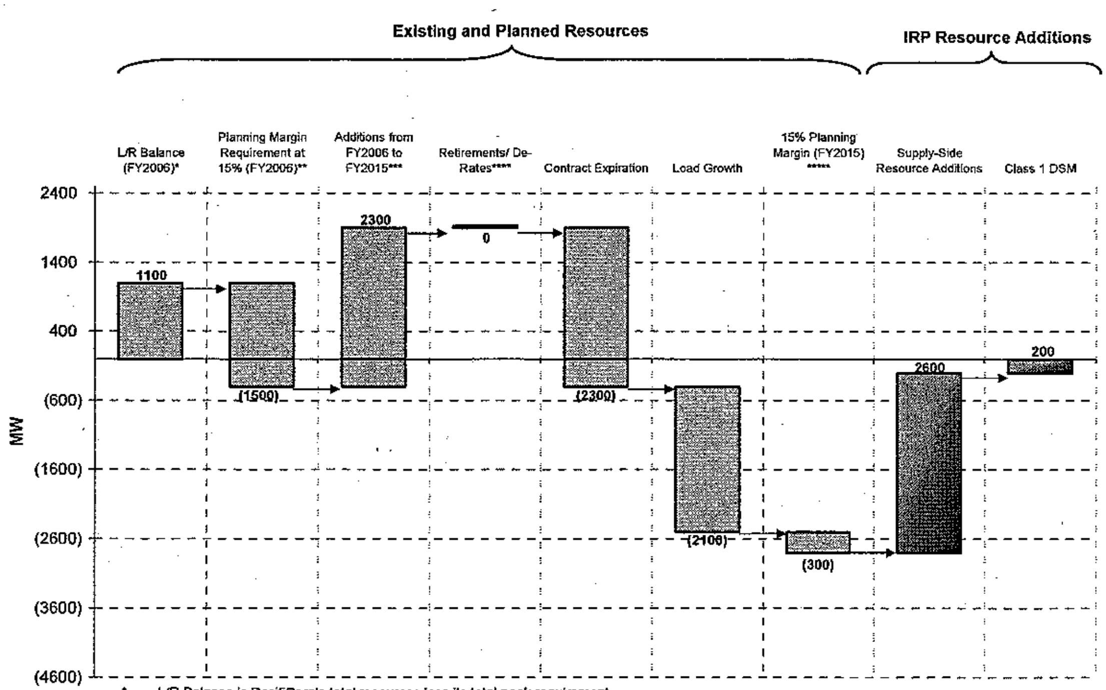
Table 9.1 – Summary of Preferred Portfolio

Location	Resource	MW	Calendar Year Installed*	Capital Cost (MM $2004)**
East	Class 1 DSM – Summer Load Control	44	2008	0
West	Class 1 DSM – Summer Load Control	44	2008	0
Utah	CCCT	525	2009	$308
Utah	Brownfield Coal Plant	575	2011	$970
WMAIN	CCCT	586	2012	$353
East	Class 1 DSM – Summer Load Control	44	2013	$0
West	Class 1 DSM – Summer Load Control	45	2013	$0
Utah	CCCT	560	2013	$349
Wyoming	Brownfield Coal Plant	383	2014	$694

* All resources are planned to be commercially operable by the summer of the installation year.
** "Capital Cost" refers to the capital cost that was used as a proxy for resource cost during the planning process. Actual costs may vary. Transmission capital costs are not included.

Figure 9.1 illustrates how the resources in the Preferred Portfolio fill the capacity requirement for the FY2006 to FY2015 time period.

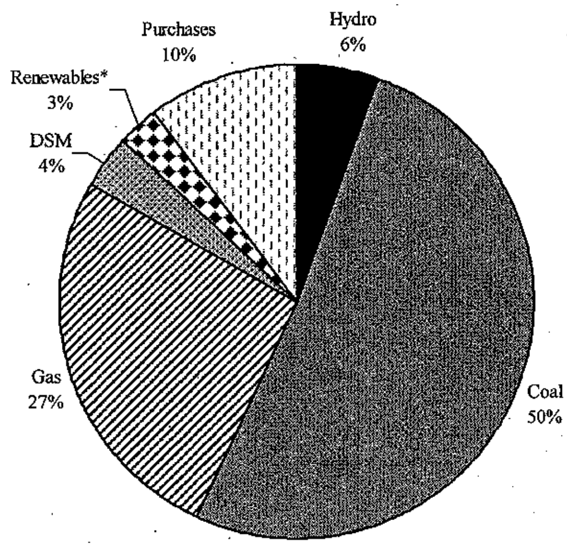
Figure 9.1 – IRP Capacity Requirement Breakdown –Rounded to the Nearest 100 MWs



* L/R Balance is PacifiCorp's total resources less its total peak requirement
** L/R Balance with 15% planning margin requirement
*** Includes plants under construction (Currant Creek & Lake Side) and planned purchases or additions (i.e. Renewables, Front Office Transactions)
**** Consists of 14 MW of hydro
***** Incremental planning margin requirement by 2015

The combination of new resources identified in the Preferred Portfolio and the existing and planned resources results in a more diversified resource portfolio for PacifiCorp. The pie chart in Figure 9.2 shows the capacity of PacifiCorp's existing, planned, and IRP resources as a percent of peak obligation (peak load + firm sales) for FY 2015.

Figure 9.2 – FY 2015 Resource Composition



* Chart reflects 20% capacity contribution of wind resources

THE IRP ACTION PLAN

Guidelines in some of the states in which PacifiCorp operates, require PacifiCorp to develop a 2-4 year IRP Action Plan. The IRP Action Plan, detailed in Table 9.2, provides an action item for any decision that needs to be made in the next 2-4 years. The Action Plan is based upon the latest and most accurate information available at the time the IRP is filed. All portfolio resource decisions outside this period will be re-evaluated in a subsequent IRP. Each action item has been categorized by addition type, resource type, timing, size, location, IRP resource evaluated, and required action.

The IRP 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 if a Paradigm shift occurs. Given historical variability and future uncertainty, the Preferred Portfolio represents the least-cost, risk informed IRP plan.

Chapter 4, Risks and Uncertainties, highlights the need for PacifiCorp to retain the ability to adjust its implementation of the IRP in light of changing circumstances. The Commissions' IRP rules also point to the need to remain flexible going forward.[31] Therefore, an important element of the Action Plan is to preserve PacifiCorp's flexibility with the objective of maintaining a least-cost portfolio as future events outside the Company's control unfold.

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. Decision processes related to the Action Plan will be iterative and occur in conjunction with the Procurement Program discussed later in this chapter. The linkage between Resource Planning and Business Planning will ensure the IRP Action Plan remains current and consistent with ongoing procurement measures.

[31] 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.*

Table 9.2 – Action Plan for Preferred Portfolio

Action Item	Addition Type	Resource Type	Timing	Size (rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	Action
1	Supply-Side	Renewables	FY 2006 - 2015	1,400	System	Wind	Continue to aggressively pursue cost-effective renewable resources through current and future RFP(s).
2	DSM	Class 2	FY 2006 - 2015	450 MWa	System	100 MW Decrements at various load shapes	Use decrement values to assess cost-effective bids in DSM RFP(s). Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and up to an additional 200 MWa if cost-effective programs can be found through the RFP process.
3	Distributed Generation	CHP	FY 2010 (summer of CY 2009) and FY 2012 (CY 2011)	n/a	System	Two 45 MW units using NREL cost estimates	Include CHP as eligible resources in supply-side RFPs.
4	Distributed Generation	Standby Generators	FY 2010 (summer of CY 2009) and FY 2012 (CY 2011)	n/a	Utah	75 MW in Utah	Include a provision for Standby Generators in supply-side RFPs. Investigate, with Air Quality Officials, the viability of this resource option.
5	DSM	Class 1	FY 2009 (summer of CY 2008)	50	Utah	Irrigation Load Control	Procure cost-effective summer load control program in Utah by the summer of 2008.
6	DSM	Class 1	FY 2009 (summer of CY 2008)	50	OR/WA/CA	Irrigation Load Control	Procure cost-effective summer load control program in Oregon, Washington, and/or California by the summer of 2008.
7	Supply-Side	Flexible, gas resource	FY 2010 (summer of CY 2009)	550	Utah	CCCT	Procure a flexible resource in or delivered to Utah by the summer of CY 2009.
8	Supply-Side	Coal resource	FY 2012 (summer of CY 2011)	600	Utah	Pulverized Coal Plant	Procure a high capacity factor resource in or delivered to Utah by the summer of CY 2011.
9	Transmission	Regional Transmission	FY 2013 and beyond	n/a	System	Transmission from Wyoming to Utah	Continue to work with other regional entities to develop Grid West. Continue to actively participate in regional transmission initiatives (e.g. RMATS, NTAC)
10	IRP Process	Modeling	2006 IRP	n/a	n/a	n/a	Incorporate Capacity Expansion Model into portfolio and scenario analysis.

IRP ACTION PLAN IMPLEMENTATION

The IRP analysis evaluates specific assets as proxies for new resources. This assumption allows modeling of different site, technology and transmission costs. It also creates a realistic framework for an implementation timeline. In implementing the Plan, however, all realistic resource options will be rigorously compared to alternatives from the market or from other existing potential suppliers. Additionally, the specifics of any resulting resource may be adjusted from the IRP proxy resource based on then current conditions. The potential risks associated with third parties being able to finance and collateralize their contractual obligations (typically associated with third party owned assets) 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, least risk provider. The proposed Procurement Program will enable consistency with Oregon restructuring requirements, also discussed later in this chapter.

The following sections will describe PacifiCorp's current procurement and hedging strategy, and the implementation strategy associated with pertinent items in the Action Plan (Table 9.2).

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 customers. This effort includes cost-effective demand side management programs, construction of the Currant Creek and Lake Side power projects, and other portfolio optimization opportunities.

PacifiCorp integrates both financial and physical hedging instruments to strategically manage the expected demand upon the physical system, which requires more than purchasing over-the-counter (OTC) standard heavy load hour ("HLH" or "6X16") power. The 6X16 product available from the OTC market is available in flat 16 hour blocks, which creates two challenges; the need to shape resources to cover superpeak demand, and the requirement to sell surplus power during various time periods, potentially at a price lower than what the block was purchased for. The overall objective is to minimize risk and deliver the most economic solutions for both the customers and PacifiCorp.

The IRP will be the high level road map to address resource requirements beyond 2008. Products similar to those detailed above will continue to be acted upon in line with the IRP Action Plan and then-current system requirements as they are critical for shaping, optimizing and minimizing the costs and risks associated with the efficient balancing and fulfillment of load service obligations across the multi-state system.

IRP Resource Procurement Strategy

To implement material resource decisions in the Action Plan, PacifiCorp intends to use a formal and transparent Procurement Program in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates. The IRP has determined the need for resources with considerable specificity and identified the desirable Portfolio and timing of need. The IRP has not identified specific resources to procure, or even determined a preference between asset ownership versus contracted resources. These decisions will be made subsequently on a case-by-case basis with an evaluation of competing resource options including updated available information on technological, environmental and other external factors such as electric and natural gas price projections. These options will be fully developed using a robust procurement process, including, when appropriate, competitive bidding with an effective request for proposal (RFP) process.

Demand Side Procurement Program

PacifiCorp uses a variety of business processes to implement DSM programs. The outsourcing model is preferred where the supplier takes the performance risk for achieving DSM results (such as the Cool Keeper program). In other cases, PacifiCorp project manages the program and contracts out specific tasks (such as the Energy FinAnswer program). A third method is to operate the program completely in-house as was done with the Idaho Irrigation Load Control program. The business process used for any given program is based on operational expertise, performance risk and cost-effectiveness. With some RFP's, such as Cool Cash and See ya later, refrigerator, PacifiCorp developed a specific program design and put that design out to competitive bid. In other cases, as with the 2003 DSM RFP, PacifiCorp opened up bidding to any type of Class 1 or 2 program in order to discover new opportunities.

RFPs will be issued to procure both Class 1 (Action Items 5 & 6) and Class 2 resources (Action Item 2). Although certain end-use technologies were used in modeling Class 1 resources, the procurement process will determine the most cost-effective program to implement.

Class 1 DSM Procurement

The Preferred Portfolio calls for 44 MW of new Class 1 DSM on the east side of the system and 44 MW on the west side of the system. This new load control will be acquired through an RFP process starting in CY 2005 and built CY 2006 through CY 2008.

Table 9.3 – CY 2008 Class 1 DSM Resource Procurement Timeline

Action Item*	Due Date
Develop draft DSM Class 1 programs and RFPs	Summer '05
Hold RFP workshops for stakeholders and potential bidders	Fall '05
RFP Process	Winter '05
Approvals & regulatory process	Spring '06
New programs begin	Summer '06

* If applicable

Class 2 DSM Procurement

As a result of the 2003 IRP process, PacifiCorp began to focus on an aggressive Class 2 DSM goal of achieving 450 MWa of new program savings over the next 10 years. Since that time, substantial progress has been made in this area. Approximately 250 MWa of existing and identified Class 2 programs (base case) are included as decrements to the load forecast for this IRP. This 250 MWa includes 86 MWa to be implemented by the Energy Trust of Oregon within PacifiCorp's service territory. Although their program savings estimates have decreased since 2003, PacifiCorp has maintained the overall 250 MWa level by increasing programs in other states.

The 200 MWa of additional programs (Action Item 2) are yet to be identified. This Action Plan focuses on pursuing the remaining portion of the 450 MWa in the long term strategy. Class 2 resources will be procured targeting end-uses that have the greatest potential to reduce load that can be acquired within the guidelines of the decrement values. Specific end-use program designs will be developed to complement existing PacifiCorp programs. The decrement values outlined in Chapter 8 present the reduction in system operations costs related to the MWh savings on the system at various load shapes. These values will be used to help determine cost-effectiveness of new program proposals obtained through PacifiCorp's procurement process.

Table 9.4 – CY 2005 Class 2 DSM Resource Procurement Timeline

Action Item*	Due Date
Develop Class 2 DSM program opportunities/specific designs	Summer '05
Draft RFP(s) for 200 MWa for 2005-2014.	Fall '05
Hold RFP workshops for stakeholders and potential bidders	Fall '05
RFP Process	Winter '05
Approvals & regulatory process	Spring '06
New programs begin	Spring/Summer '06

*If applicable

Supply Side Procurement Program

Because of the need for flexibility and agility in resource procurement and potential changes in legal and regulatory requirements with respect to competitive bidding, this Action Plan does not designate specific supply blocks that will be subject to competitive bidding. The role of RFPs related to a specific supply side resource procurement decision by PacifiCorp (Action Items 3, 4, 7, & 8) will depend upon the size, type, and location of the resource being considered as well as any applicable Federal or state-specific laws and/or regulatory requirements. A comparison of all competing alternatives, including contracted resource options, will be made before PacifiCorp makes a build decision. This comparison will consist of the identification of relevant alternative third parties and/or contracted resource options for comparison against the appropriate market. When applicable, comparisons will also be made against existing resource options that PacifiCorp may contractually hold or negotiate. In instances where PacifiCorp feels a formal RFP issuance is warranted, due to specific geographic, legal or regulatory criteria, or other market-related conditions, one will be issued.

The evaluation of specific resource alternatives, whether build or contracted, will be performed on the same basis, using the same techniques, and based on the then-current regulatory compact for cost recovery. All evaluations will utilize the best available information reasonably known at the time. This means that certain inputs are bound to change during the lead-time associated with any plant construction. As such, a resource associated with a newly constructed asset, regardless of the asset being constructed by a third party or PacifiCorp, may be subject to a level of uncertainty that is higher than a contractual arrangement with a third party who is not relying on the construction of a new asset.

In general and unless required by applicable law or regulatory requirement, it is not currently envisioned that evaluations would typically be performed by an independent third party.

However, in certain circumstances or where legal or regulatory criteria dictate, such as where an affiliate transaction or self-built resource may be a potential alternative, an independent consultant may be retained to monitor and 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. The feedback PacifiCorp receives 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. However, stakeholders are anticipated to have an opportunity to comment on formal RFPs to the extent they are reviewed during a Commission review process.[32]

<u>Common Features of Supply Side RFP's</u>
At a minimum each supply side RFP will include an adequate amount of information to enable bidders to submit a compliant bid. Subject to applicable laws and/or regulatory rule/order, such information may include, but may not be limited to, the following type of information:

- Amount
- Resource being solicited
- Term
- Delivery point(s)
- Evaluation horizon
- RFP process
- Evaluation methodology
- Environmental assumption
- Benchmark comparison
- Use and role of an independent monitor
- Applicable screening criteria (such as credit requirements and/or other factors)

Prior to the issuance of any supply side RFP, PacifiCorp will determine whether the RFP should be "all-source" or if the RFP will have limitations as to amount, proposal structure(s), fuel type or other such considerations. Benchmarks will also be determined prior to RFP being issued and may consist of the then-current view of market prices, a self-build option, a contractual arrangement, or other such benchmark alternative. Externalities will be determined based on the form and format of each procurement process. It is anticipated that the assumptions utilized will be consistent with what is in the IRP unless such assumptions are not applicable or new/updated information is available to inform the process.

[32] Such as pursuant to Oregon Order No. 91-1383.

Timeline for Supply Side Resource Additions

As was stated earlier in this chapter, PacifiCorp intends to use a formal and transparent Procurement Program in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates. Two material resource additions that will need to be made within the Action Plan time horizon occur in the summer of CY 2009 (Action Item 7) and in the summer of CY 2011 (Action Item 8). The two tables below (Tables 9.5 and 9.6) provide an initial timeline associated with these resource procurements. These timelines assume reliance on RFPs for procurement and the continuation of current competitive bidding models and guidelines.

Table 9.5 – CY 2009 Resource Procurement Timeline

Action Item*	Due Date
Retain independent monitor and formulate RFP content	Winter '05 – Spring '05
Hold pre-draft RFP workshops for stakeholders and potential bidders	Summer '05
RFP Process	Fall '05 – Summer '06
Approvals & regulatory process	Summer '06 – Spring '07
Construction period if bidder proposes to build an asset that requires up to 24-months to construct	Spring '07 – Summer '09

* If applicable.

Table 9.6 – CY 2011 Resource Procurement Timeline

Action Item*	Due Date
Retain independent monitor and formulate RFP content	Summer '05 – Winter '05
Hold pre-draft RFP workshops for stakeholders and potential bidders	Winter '05 – Spring '06
RFP Process	Spring '06 – Spring '07
Approvals & regulatory process	Spring '07 – Winter '07
Construction period if bidder proposes to build an asset that requires up to 42-months to construct	Winter '07 – Summer '11

* If applicable.

Qualifying Facilities and Distributed Generation

Distributed generation, such as CHP and Standby Generators, can be a valuable contributor to filling the resource gap. PacifiCorp's procurement process will continue to provide an avenue for such new or existing resources to participate. These resources will be advantaged by being given a minimum bid amount (MW) eligibility that is appropriate for such an alternative but that is also consistent with PacifiCorp's then-current and applicable tariff filings (QF tariffs for example). There is also an expectation that since these resources are usually linked to a customer process, the costs associated with the project will reflect the fact that the host is benefiting from the resource. Therefore, PacifiCorp would expect this provides the resource a cost advantage when submitting a bid and, subject to accounting treatment on a case by case basis, a potential advantage in the debt-related calculation if the proposed structure does not account to be a capital lease. In addition, those distributed generation resources that qualify for QF status will contribute to the resource mix as customers and QF developers bring them on line.

PacifiCorp will continue to participate with regulators and advocates in legislative and other regulatory activities that help provide tax or other incentives to renewable and distributed resources.

Consistency with Oregon Restructuring

The Oregon Restructuring legislation (SB1149) states that *electric companies must include new generating resources in revenue requirement at market prices, and not at cost.*[33] The Oregon PUC has not resolved how this provision would be implemented or if it should be modified, and has a pending investigation into the matter.[34] As noted elsewhere in this report, the IRP has not identified specific resources to procure, or even determined a preference between asset ownership versus contract resources. 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.

Transmission Expansion

PacifiCorp has been an active participant in both the Rocky Mountain Area Transmission Study (RMATS) and the Northwest Transmission Assessment Committee (NTAC). The transmission alternatives being discussed in these sub-regional forums could result in greater access to geographic regions that may contain lower delivered cost resource options, such as coal and wind, and could help the Company better balance the system, especially in light of projected rapid load growth.

PacifiCorp recognizes the importance of coordinating regional transmission planning with the Company's resource strategy. For example, the existing transmission constraints in and out of Utah limit generation sourcing and fueling options. Regional transmission initiatives, like RMATS and NTAC, may provide regional benefits that cannot be fully recognized by one utility or load serving entity.

PacifiCorp evaluated a portfolio (Portfolio Q) that was developed based on the Phase 1 RMATS results. Portfolio Q and the Preferred Portfolio had the same resource additions in the near term (until FY 2013), however, in the outer years, this portfolio tested the result of replacing a gas resource near the load center in Utah with a Wyoming coal resource and transmission scenario. This portfolio performed well in the stochastic and high gas scenario analysis, and PacifiCorp will continue to actively evaluate these transmission expansion opportunities.

PacifiCorp is also working to develop Grid West, an independent regional transmission entity. Other regional transmission owners are involved in this effort (federal, provincial and seven other investor-owned utilities), as are a broad stakeholder group. The Interim Grid West Board

[33] OAR 860-038-0080(1)(b).
[34] Oregon Docket UM 1066

has been established and it is expected that the independent Developmental Board will be seated in CY2005.

When Grid West becomes operational (expected in CY2007), it will be responsible for transmission planning over its footprint. Since the operation of Grid West is several years in the future, PacifiCorp has also been active in various transmission planning initiatives with the WGA, SSG-WI and sub-regional planning processes (e.g. RMATS and NTAC). Once Grid West becomes operational, PacifiCorp anticipates some of the regional planning initiatives will be folded underneath the Grid West planning function.

It's PacifiCorp's belief that the independent, broad geographic scope of Grid West will lead to higher likelihood of needed transmission infrastructure being constructed. Grid West will be a backstop for transmission reliability and will be in a position to make independent assessments of the beneficiaries and the appropriate cost recovery for all needed transmission expansion projects.

Approach to Transmission Expansion

PacifiCorp plans to take the following steps in order to keep a transmission expansion opportunity as a viable long term strategy for meeting future load.

- Begin appropriate resource procurement processes early enough to allow a transmission project to potentially be a viable alternative.
- Continue to promote the establishment of a regional independent transmission entity that can ensure better efficiency of the network and better facilitate planning, development and operation of transmission expansions.
- Continue to work with other interested parties in regional forums to conduct power flow and stability studies, address siting and right-of-way issues, resolve cost allocation and other pricing issues, and refine planning studies for economically sound transmission expansions.
- In cooperation with regulators and other stakeholders, pursue pricing principles to equitably allocate transmission expansion costs and attract needed capital, and pursue ownership and financing arrangements to make projects viable.
- Improve modeling capabilities to better assess the economic costs and benefits of transmission alternatives, and to better integrate resource and transmission planning.
- Continue to study incremental transmission-related projects that increase the transfer capability of the system and/or increase transfer capability or add interconnections with other electrical control areas.
- Work to integrate project recommendations from RMATS and NTAC into west side expansion planning/implementation efforts by the Seams Steering Group – Western Interconnect (SSG-WI).

Since transmission typically has a long lead time associated with it, the IRP will monitor progress of these efforts, and as detailed information becomes available, incorporate more specific project evaluation into the next IRP.

ACTION PLAN PATH ANALYSIS

The candidate resources modeled in the Preferred Portfolio were used to identify the type, timing and size of the resource decisions outlined in the Action Plan (Table 9.2). This resource combination was low cost on a deterministic expected value basis and also had the least amount of variability in the expected outcome given uncertainty in the base assumptions (stochastic and scenario risk analysis). The majority of the items in the Action Plan will be acted upon prior to the next IRP planning cycle. Therefore, the time-frame for these decisions is short and, as a result, there are not expected to be many changes in the projected future that will likely affect the decision. For example, a paradigm shift, such as the establishment of Grid West, may change the way in which resources are procured in the future but will probably not affect the fact that resource decisions have to be made in the next two years.

It is difficult to anticipate all the various circumstances that could arise over the Action Plan time horizon. Therefore, the plan needs to remain flexible so as to be modified if a different future unfolds or if there is a fundamental shift in the underlying assumptions. As such, the Action Plan Path Analysis should allow for use of all appropriate procurement paths to meet customer needs and defer to the Company's judgment in determining which path is best suited based on information available at that point in time and given the particular situation. These alternative paths would likely include implementing an alternative bid process, moving directly to negotiations with known suppliers, evaluating the availability of additional resources that may only be available for a finite term, or developing generation on a site available to the Company. In any event, PacifiCorp must have the flexibility to act to meet our obligation to serve, while at the same time justifying the prudence of an action. Regardless of the path taken, PacifiCorp plans to keep regulators and their staffs apprised of key resource activities, including progress on the Procurement Program.

In the next IRP Planning Cycle, PacifiCorp plans to use the Capacity Expansion Model (CEM) to inform its Action Plan Path Analysis (Action Item #10). Since the CEM was not available to do this analysis in the 2004 IRP, PacifiCorp identified three primary circumstances that could require PacifiCorp to make a decision to take a different path than what is outlined in the Action Plan and then discussed what action(s) could be taken in the event a change occurred. The three circumstances are: 1) the inability to procure designated resources in the required time-frame to meet the need, 2) a significant shift (increase or decrease) in the forecasts of loads and/or resources, and 3) a State or Federal mandate is imposed upon the Company.

<u>Inability to Procure Designated Resources</u>

There are various reasons why there may not be an ability to procure a designated resource in the timeframe identified in the IRP. For example, there may not be any cost-effective opportunities available through an RFP or the successful RFP bidder may experience delays in permitting and/or default on their obligations. For example, if a cost-based, self-build alternative is identified as the evaluation benchmark in a RFP, it may be that the identified benchmark (the self-build alternative in this case), is still not economic as compared to the forward view of market prices. These issues could require PacifiCorp to take a different action than identified in the IRP.

Possible paths PacifiCorp could take if there was either a delay in the online date of a resource or if it was no longer feasible to acquire a given resource include:

- Move up the delivery date of the next resource
- Make a near-term purchase until a longer-term alternative is identified
- Temporarily drop below the 15% Planning Margin for a period of time

Shift in the Forecasts

Material shifts in either loads or resources could affect the timing and size of major resource additions. Examples of significant changes that could occur include a large loss of load under retail competition (OR SB1149), the dramatic reduction in load from a large end-use customer or customers or a terrorist event that could impact the economy. Another example includes a substantial increase in the power that is sold to PacifiCorp from Qualifying Facilities which could result in a decrease in the need for a new resource and could change the timing and/or mix of the planned resources.

Possible paths PacifiCorp could take if a major shift in either the loads or resources would occur include:

- Delay or accelerate resource procurement(s)
- Reassess the amount and timing of the need

State or Federal Mandate Imposed

There could be a circumstance where a state or federal requirement would come into effect and PacifiCorp would be required to comply. Examples of such a requirement could be a state or Federal Renewable Portfolio Standard or Multi-Pollutant legislation that is different than what was modeled in the Scenario risk analysis.

Possible paths PacifiCorp could take if one of these mandates was required include:

- Re-evaluate current procurement activities to ensure adequate resources were being procured to meet the new standard
- Review action items to ensure proposed actions wouldn't conflict with new requirement

SUMMARY

The Action Plan aims to ensure PacifiCorp will continue meeting its obligation to serve customers at a low cost with manageable and reasonable risk. An important factor in managing both customer and company risk is maintaining a strong investment grade credit rating in order to procure new resources on the best available financial terms. 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.

The Action Plan is based on 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.

The IRP Action Plan is the primary driver for PacifiCorp's resource procurement going forward. In implementing the Plan, all resource options will be rigorously compared to alternative resource options either from the market or from other existing potential electricity suppliers. The proposed Procurement Program will also ensure consistency with anticipated ratemaking requirements, including industry restructuring implementation in Oregon.