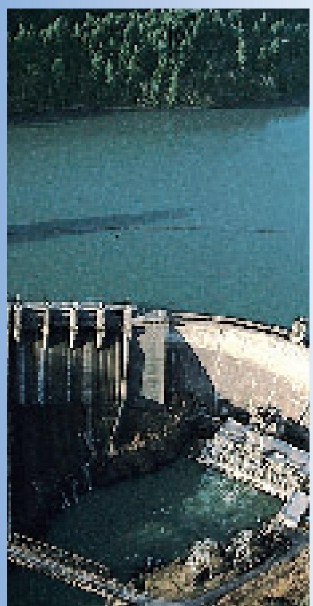

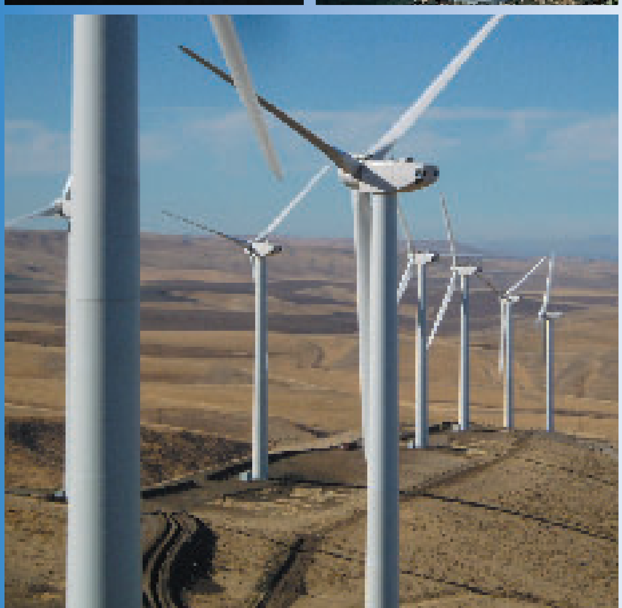

2004 Integrated Resource Plan

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.

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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.

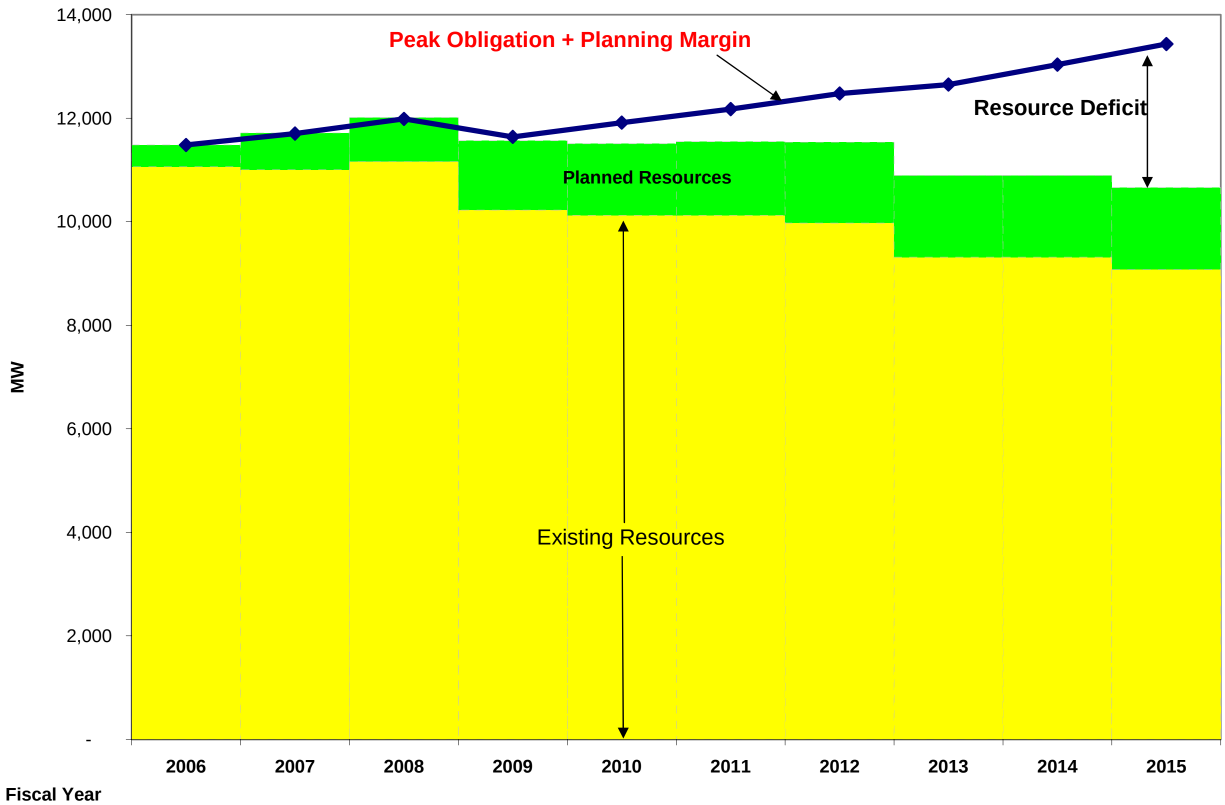
RESOURCE NEEDS ASSESSMENT

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>

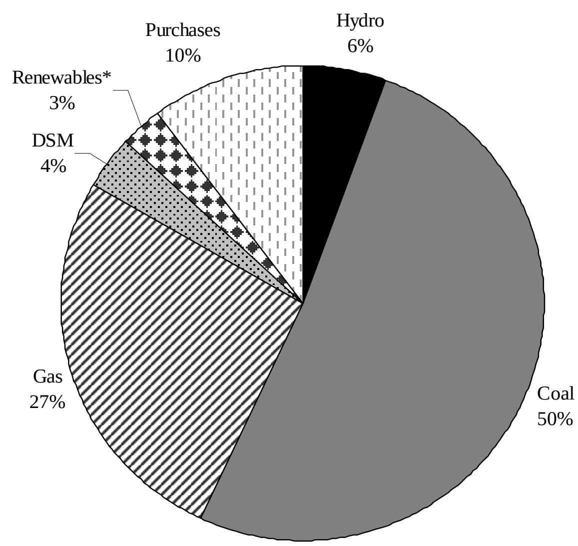
PacifiCorp intends to implement many elements of the Action Plan utilizing a formal and transparent Procurement Program. The IRP has determined the need for resources with considerable specificity, and identified the desired Portfolio and timing of need. The IRP has not identified specific resources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



* Chart reflects 20% capacity contribution of wind resources

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.

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

The practice of integrated resource planning must be dynamic and adaptive to changing circumstances if it is to meet its objective of guiding resource choices to the lowest cost and lowest risk alternatives. This chapter provides an overview of emerging trends and recent developments in PacifiCorp's situation and evolving business environment. This discussion underscores those emerging issues that are addressed as part of the current planning cycle.

Two major issues hang over the most significant resource choices that PacifiCorp must make as we strive to meet customers' future needs. These issues are uncertainties with regard to: 1) the future cost and supply of natural gas in relation to coal and 2) the future cost of, or constraints on, air emissions, carbon dioxide emissions in particular. These uncertainties directly impact cost comparisons between new generation resources fueled by natural gas and by coal. Technology change is a third uncertainty closely related to these choices. These issues are presented below, following an overview of the current energy marketplace and business environment, within which PacifiCorp's resource decisions must be made.

EVOLUTION OF THE ENERGY MARKETPLACE

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 procurement processes 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 does not have a clear obligation to continue to plan for the future requirements of its existing customers in all jurisdictions it serves. Moreover, the Company's Multi-State Process emphasized that the lowest aggregate system cost, suitably balanced with risks, should be the objective of resource actions. In any case, PacifiCorp's portfolio of supplies remains tied to broader wholesale energy markets.

RECENT EXPERIENCE IN THE WESTERN ENERGY MARKETPLACE

Each month millions of megawatt-hours of energy are traded in the wholesale electricity marketplace of the Western Interconnect. These transactions yield economic efficiency by assuring that resources with the lowest operating cost are serving demand in a region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp has historically participated in the wholesale marketplace in this fashion, making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on terms and time scales ranging from hourly to years in advance. Without it, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supplies that would go unutilized in all but unusual circumstances and would substantially diminish its capability to efficiently match delivery patterns to the profile of customer demand. The market is not without its downside, as the experiences of the 2000-2001 market crisis in the west illustrated.

<u>The Electricity Market Crisis of 2000-2001</u>

The reality of new risks in the competitive marketplace became painfully clear in the WECC electricity crisis of 2000 and 2001. In the prior decade, as markets prepared for or implemented deregulation, little new generation had been installed in the region in relation to demand growth. A severe shortage of supply became apparent in May 2000. Later in the year, a rare severe west-wide drought significantly reduced WECC hydroelectric generation resources. With prices set by the market rather than by regulation based on cost of supply, wholesale electricity prices rose to unprecedented levels. To compensate for the hydroelectric energy shortage, inefficient gas-fired generation (normally not expected to run) was operated often around the clock. This occurred at the same time that natural gas markets were experiencing their own strains, due to a tight supply-demand balance and a major pipeline failure. The tight market conditions and high prices were also magnified by flaws in market design, especially in California. Indeed, a major criticism of the original California market design was its exclusion of long-term forward contracting, which undoubtedly contributed to the lack of new generation additions. Other flaws allowed some participants to manipulate markets so as to boost prices inordinately.

Almost as quickly as the crisis erupted in 2000, it rapidly retreated in 2001. Figure 1.1 illustrates the rapid price run-up and retreat and unprecedented price volatility through this short period.

Figure 1.1 – Electricity Price Volatility 2000-2001

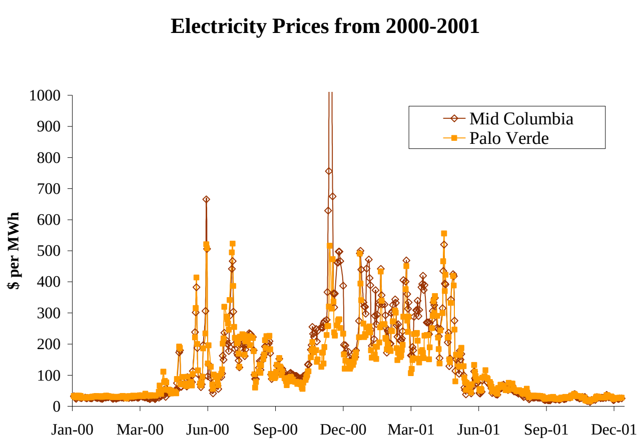
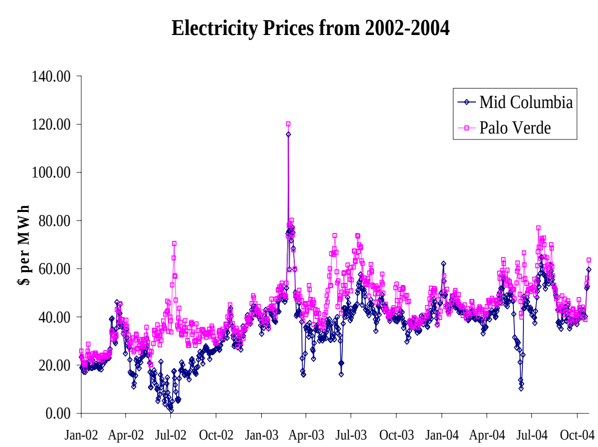


Figure 1.2 – Electricity Price Volatility 2002-2004



<u>Return of Market Stability and Evolution of Merchant Sector</u>

Electricity prices began to drop rapidly from their unprecedented highs in mid-2001, aided directly by FERC price caps, other mitigation procedures and declines in demand in response to price increases and mild weather conditions. Similar factors also helped ease natural gas demand while gas production rebounded, combining to bring gas prices down dramatically. In addition, new generation resources coming on line in the western system also helped restore reserve margins and reduce the financial exposure of load serving entities. Figure 1.2 plots the return to wholesale price stability in the 2002-2004 period, illustrating the substantial recovery of the marketplace from the 2000-2001 crisis.

The wave of generating capacity additions that began in 2001 has far surpassed demand growth and plant retirements in the WECC for several years. These have restored reserve margins to adequate levels, and in some regions of the WECC created a substantial supply cushion. As a result, wholesale prices for electricity traded in short-term markets over the last two years have been generally at levels that exhibit little or no premium over operating costs of marginal generating units, and adequate reserve margins are expected to prevail for several years to come, in aggregate. The potential does exist for scarcity to enter into the supply/demand balance in more localized areas under adverse conditions. Nevertheless, there is a very low probability of a return to 2000-2001 crisis conditions.

A large percentage of the capacity added to the WECC since 2001 was built and financed by merchant generators, frequently without the benefit of long-term contracts for the sale of plant output. This has left a number of merchant generators in distressed financial condition and reduced the likelihood of another speculative boom in new generation construction. The role of the merchant sector is thus evolving, with a shift towards reliance on long-term forward transactions and with improving depth and liquidity in short- and mid-term energy trading.

A shift to longer-term power purchase agreements, rather than shorter term and spot market transactions, may enable merchant generators to provide more cost effective alternatives in competitive acquisition processes.

At the same time that the wave of new capacity additions restored adequate reserve margins to the Western Interconnect, a number of market reforms have been undertaken to address the market dysfunctions that enabled the market crisis. For example, the California Independent System Operator (ISO) has embarked on a series of reforms and improvements that address structural failures and mitigate the potential exercise of market power in California, the vortex of the market crisis. In a similar vein, the FERC adopted new market behavior rules applicable throughout the U.S. aimed at curbing potential abuses and assuring that market-based pricing is also just and reasonable. The major California utilities are now able and indeed encouraged to forward hedge demand requirements rather than rely exclusively on volatile daily markets. Finally, the emergence of capacity reserve requirements or standards in the Western Interconnect will assure that an adequate level of reserves will extend into the future, extending market stability into the long run. California is a prominent example in this effort, with the adoption of reserve requirements of between 15% and 17% for the major load serving entities within that state. WECC and other western efforts give indications that participants will be expected to provide for adequate supplies for expected customer demand. Should these trends continue, they will substantially mitigate the risk of severe capacity shortages and the repeat of a marketplace crisis of 2000-2001[6].

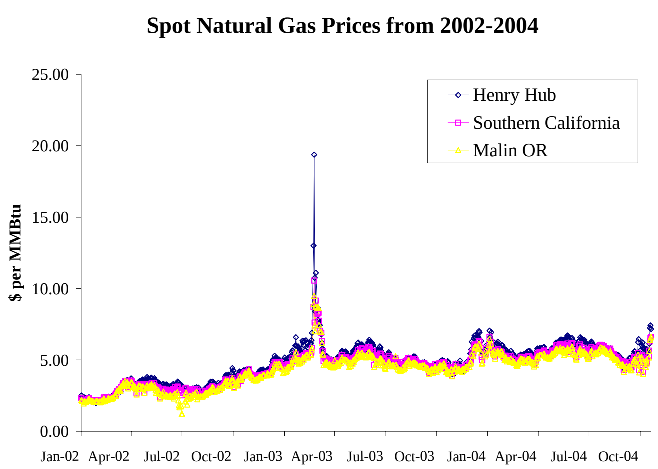
[6] See Appendix A for further discussion and projections of supply margins in the Western Interconnect.

In conclusion, relative stability has returned to the marketplace, allowing it to provide efficiency going forward, so long as reasonable supply/demand balance is maintained. This allows PacifiCorp to utilize the marketplace as a reasonable component of its supply portfolio, both through balancing purchases and sales and as a supplement to generating assets through layered term purchases.

NATURAL GAS SUPPLY AND DEMAND ISSUES

Natural gas fuels about 90% of the more than 30,000 MW of capacity additions in the Western Interconnect since 2001. Similarly, 182,000 MW of capacity additions throughout the U.S. are 94% gas fueled. Over the last five years, new highly efficient combined cycle combustion turbine generation has become the technology of choice for a variety of reasons, including cost, timing and ease of development. Over the same period of time, natural gas prices have escalated substantially and demonstrated unprecedented volatility, as illustrated in Figure 1.3. These prices are not set by gas fired generation, however, but by the aggregate supply-demand balance in a well integrated North American natural gas market.

Figure 1.3 – Historic Natural Gas Prices



Power generation currently accounts for about 26% of annual US demand for natural gas. This will inevitably grow as older non-gas generation is retired and the recent wave of gas fired capacity additions increases output to meet demand growth. This growing demand for gas will likely add a summer weather sensitivity and new source of price volatility. Residential and commercial demand for gas accounts for about 24% of annual demand, with meager growth expected. Industrial demand for gas is the most price-sensitive, and indeed has dropped in response to current market prices. This loss of price-responsive industrial demand has taken some flexibility out of the supply-demand equation, and as a consequence contributed to gas price volatility.

North America is supplied by a large and diverse set of natural gas producers operating in a number of geographically dispersed producing regions tied to markets and demand by an extensive pipeline network. Two supply issues have emerged in recent years. First, declines in production from mature producing regions are forcing producers to turn to frontier regions for new supplies. This raises the prospect of an upward trend in natural gas costs. Second, the supply-and-demand dynamics of natural gas portend continued volatility in gas prices, especially when little spare production capacity is evident on the horizon. (An examination of natural gas reserves and supply and demand forces that will shape the future North American gas market is presented in greater depth in Appendix A.)

Mature gas producing areas (onshore and shallow water Gulf of Mexico and the mid-continent, including the Permian Basin), accounting for about two-thirds of U.S. domestic gas production, have entered an inevitable decline phase, even in the face of high prices. These declines are partially offset by production increases from the Rocky Mountain region, which remains the bright spot in US supply growth and a major exporter of gas to consuming regions of North America. In the absence of substantial growth in North American gas production, increased reliance on imported liquefied natural gas (LNG) is forecasted, and a wave of proposals and projects for LNG terminals has been forthcoming.

A number of examinations have been undertaken of proved and technically recoverable reserves of natural gas in North America and the vast reserves on other continents that can be accessed with LNG imports. These confirm that accessible supplies will be adequate to meet growing demand for gas over the projected life of potential gas fired generation projects within this IRP's investment horizon. However, even with substantial LNG contributions to North America, prices will remain uncertain and tend to be set by marginal production in declining mature areas, where finding and development costs as well as production costs are increasing.

The marginal additions to supplies projected from LNG will take several years to materialize, leaving forward prices and forecasts at relatively high levels for three or more years. In addition, a continued tight supply/demand balance, limited storage capacity and continuing losses from the most price-responsive industrial demand sector all portend elevated price volatility for natural gas. A key issue for integrated resource plans, therefore, is the effect of natural gas price uncertainty and volatility on natural gas as a generation fuel.

While electric generation demand for gas has contributed to aggregate demand, this effect is spread across the North American gas market as a whole rather than in any single region. By the same token, future natural gas prices in Rocky Mountain and Pacific Northwest regional markets will be largely determined by overall supply and demand for the North American gas market, rather than any incremental demand in either of those markets.

PacifiCorp's resource portfolio has historically been relatively insulated from natural gas price impacts. Natural gas fired generation currently contributes only about 10% of supply capacity and recently has supplied less than 5% of annual energy delivered to our customers. Looking forward, however, future natural gas prices and the role of gas-fired generation are key issues in determining supply portfolios that balance low cost and low risk objectives.

FUTURE EMISSION COMPLIANCE ISSUES

Over the next decade, PacifiCorp faces a changing environment with regard to electricity plant emission regulations. Although the exact nature of these changes remains uncertain, they are expected to impact the cost of future resource alternatives and the cost of existing resources in PacifiCorp's generation portfolio. No greater uncertainty exists in this area than the potential for global climate change and policy actions to control carbon dioxide (CO_2), the principal emission associated with climate change. The section below briefly summarizes issues surrounding currently regulated air emissions; these issues are described in greater depth in Appendix A. The potential for future regulation of CO_2 emissions due to climate change concerns and PacifiCorp's climate change strategy are then discussed in detail.

Currently Regulated Emissions

Currently, PacifiCorp's generation units must comply with the federal Clean Air Act (CAA) which is implemented by the States subject to Environmental Protection Agency (EPA) approval and oversight. The Clean Air Act directs EPA to establish air quality standards to protect public health and the environment. PacifiCorp's plants must comply with air permit requirements designed to ensure attainment of air quality standards as well as the new source review (NSR) provisions of the CAA. NSR requires existing sources to obtain a permit for physical and operational changes accompanied by a significant increase in emissions.

Within the current federal political environment there exists a contentious debate over establishing a new energy policy and revising the CAA in order to reduce overall emissions from the combustion of fossil fuels. Currently, the debate focuses on emission standards and compliance measures for sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury (Hg), particulate matter (PM), and regulation of carbon dioxide emissions. Several proposals to amend the Clean Air Act to limit air pollution emissions from the electric industry are being discussed at the national level. Specifically, a number of alternative proposals for federal multi-pollutant legislation would require significant reductions in emissions of SO_2, and NO_X, and establish new definitive standards for mercury. Some proposals also contain measures to limit CO_2 and to revise certain other regulatory requirements such as NSR.

Within existing law, EPA's Regional Haze Rule and the related efforts of the Western Regional Air Partnership will require emissions reductions to improve visibility in scenic areas. Additionally, newly proposed administrative rulemakings by EPA, including the Clean Air Interstate Rule and the Utility Mercury Reductions Rule, seek to require significant reductions in emissions from electrical generating units. The outcome of the current debate, manifested in new legislation or rulemakings, will shape PacifiCorp's emission requirements over the coming decade. Compliance costs associated with anticipated future emissions reductions will largely depend on the levels of required reductions, the allowed compliance mechanisms, and the compliance time frame.

In accordance with ScottishPower's environmental vision, PacifiCorp is committed to responding to environmental concerns and investing in higher levels of protection for its coal fired plants. PacifiCorp is committed to meeting stringent new air quality standards and seeks to collaborate with policy makers to institute a program to significantly reduce air emissions and provide operational certainty for its coal fired assets over the next 15-20 years.

Climate Change

Climate change has emerged as an issue that requires attention from the energy sector, including utilities. The global scientific community has offered compelling evidence of the effect of man-made greenhouse emissions on future climate conditions. It is therefore prudent to recognize within the IRP framework the potential for government imposed environmental costs associated with climate change policy.

PacifiCorp and parent company ScottishPower recognize these issues surrounding climate change. ScottishPower's environmental goals include achieving lower levels of CO_2/kWh across the U.K. and U.S. portfolios to help combat climate change. PacifiCorp specifically has a goal of addressing climate change with additions of renewable generation and conservation and, where feasible, offsets. In recognition of potential future regulation, PacifiCorp also has adopted quantitative estimates of future CO_2 emissions costs.

Impacts and Sources

The Intergovernmental Panel on Climate Change (IPCC), established by the World Meteorological Organization and the United Nations Environment Program as the top world scientific body on climate change, has found with a high degree of certainty that average global surface temperatures will rise during the course of this century, accompanied by other climate change impacts, including precipitation increases, glacier retreat and sea level rise. The IPCC finds that our understanding of regional impacts is much less certain at this point, as compared to expected average global impacts. Research on local impacts continues to evolve and improve. PacifiCorp will track such developments to see how they can inform our assessment of regulatory risk and even operational impacts, though currently such impacts are too uncertain to incorporate into planning.

The U.S. contributed a quarter of global, man-made greenhouse gases (GHGs) in 1999. U.S. emissions have declined relative to economic activity (i.e., tons per unit of gross domestic product), but absolute emissions continue to rise. Even so, according to the U.S. Energy Information Administration (EIA), emissions from industrialized nations will actually drop as a percentage of global emissions, with emissions from the developing world (e.g., China and India) expected to represent 42% of global emissions in 2020.

According to the EIA, the electricity sector contributed 39% of all man-made GHG emissions in the U.S in 2002. The sector's emissions rose by 25% from 1990 to 2000. The EIA projects the sector's emissions to represent 41% of national emissions in 2025. Increased electricity consumption by the residential, commercial and industrial sectors is primarily responsible for growing emissions. The emissions intensity (lbs/kWh) will actually grow only 2% from 2002 to 2010 and stay level through 2025, as generation fueled by natural gas and renewables grows.

PacifiCorp carefully tracks CO_2 emissions from operations and reports them in the ScottishPower Environmental Performance Report. (The report is available at http://www.scottishpower.com/pages/esir.) CO_2 emissions from owned power plant capacity, transportation, internal energy use, and sulfur hexafluoride use for distribution and transmission totaled 37.7 million tons in 2002. That compares to 37.5 million tons in 2000, or a 0.6% increase. Emissions intensity from owned power plants (defined as emissions per unit of power generated) remaining similarly flat during the 3-year period, moving from 0.97 tons/MWh in 2000 to 1.01 tons/MWh in 2002.

International, Federal and State Policies

Numerous policy activities have taken place and continue to develop. At the global level, most of the world's leading GHG emitters, including the European Union (EU), Japan, China, and Canada, have ratified the Kyoto Protocol. Most recently, Russia now has moved to ratify and put the Protocol into effect among the ratifying nations, without U.S participation. The Protocol sets an absolute cap on GHG emissions from industrialized nations from 2008 to 2012 at 7% below 1990 levels. The Protocol calls for both on-system and off-system emissions reductions. Due to a strong push from the EU, the role of off-system reductions is limited. Emissions reduction credits associated with both on- and off-system reductions are tradable, thereby encouraging efficient investments to minimize the cost per ton of carbon dioxide (CO_2) of meeting the Kyoto limits.

While the U.S. has thus far rejected the Kyoto Protocol, numerous proposals to reduce greenhouse gas emissions exist at the federal level. The proposals differ in their stringency and choice of policy tools. The Bush Administration has proposed an 18% voluntary carbon intensity reduction target, i.e., emissions per unit of economic output. Such an approach could translate into a tons/MWh approach in the electricity sector.

Senators Lieberman and McCain have proposed an approach to limit national emissions in 2010 onwards to 2000 levels. The bill garnered 44 votes in the U.S. Senate in 2004. PacifiCorp expects additional cap-and-trade proposals in the near future.

In response to sparse federal activity, state policy has grown in prominence. In 1997, Oregon passed the first state siting law that considered CO_2 emissions as a criterion for siting new power plants. The law requires new plants to reduce CO_2 emissions 17% below the most efficient gas fired electric generating plant in the nation, typically by paying The Climate Trust a set rate per ton of CO_2, currently 85 cents. Washington passed similar legislation in 2004.

In April 2002, New Hampshire passed legislation aimed at reducing CO_2 emissions. The bill calls for reductions to 1990 levels by December 2010. Massachusetts has also adopted CO_2 limitations on its six existing fossil-fired power plants. Following these individual state efforts, the entire New England region as well as New York, New Jersey and Delaware have committed to developing a regional cap on GHG emissions from the electric sector.

California passed legislation in 2002 that directs the Air Resources Board to set maximum feasible and cost-effective reduction of GHG emissions from passenger cars and light trucks. The legislation has survived legal appeals and will likely face further appeals in the near future. California also established a greenhouse gas emission registry (the California Climate Action Registry) so that entities can apply stringent and acceptable accounting standards to their inventories.

Many states also have policies that enable GHG reductions, without specifically focusing on GHG emission rates or caps. For example, 17 states including California have passed renewable portfolio standards, 16 states including Oregon have public benefits funds for renewables and energy efficiency, and most states have incentives for renewables and efficiency, including Utah's and Wyoming's recent passage of sales tax exemptions for renewable energy equipment.

Corporate Strategy
PacifiCorp is committed to engage proactively with policymaking focused on GHG emissions issues through a strategy that includes the following elements.

- Policy: PacifiCorp has supported legislation that enables GHG reductions while addressing core customer requirements. Policies include a federal renewable portfolio standard and appliance efficiency standards. PacifiCorp will continue to work with regulators and legislators to identify viable tools for GHG emissions reductions.
- Planning: PacifiCorp has incorporated a reasonable range of values for the cost of CO_2 in the IRP to reflect the risk of future regulations that can affect relative resource costs[7].
- Procurement: PacifiCorp recognizes the potential for future CO_2 costs in RFPs, consistent with its treatment in the IRP.
- Accounting: PacifiCorp has adopted transparent accounting of GHG emissions by joining the California Climate Action Registry. The Registry applies rigorous accounting standards, based in part on those created by the World Business Council on Sustainable Development and the World Resources Institute, to the electric sector.

The strategy is focused on meaningful results, including installed renewables capacity and effective DSM programs that directly benefit customers. PacifiCorp received the 2004 American Wind Energy Association Utility Leadership Award for its multiple efforts on advancing renewables. It has also received substantial praise from environmental groups for effective energy conservation efforts in Utah and elsewhere. While these efforts provide multiple benefits of which lower GHG emissions are a part, they are clearly attractive within an effective climate strategy and will continue to play a key role in future efforts.

PacifiCorp will continue to refine its actions within each of the above categories as necessary to provide reliable, least-cost and least-risk service for the benefit of our customers.

IMPLICATIONS OF MARKET DEVELOPMENT AND FUNDAMENTAL TRENDS

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

[7] Similar to the approach in various U.S. legislative proposals and to various international implementation plans, PacifiCorp has assumed a cap and trade program in this IRP. The IRP models a phase-in beginning in FY 2010, capped at year 2000 level emissions. After phase-in, each carbon allowance is valued at $8/ton in year 2008 dollars. Additional detail on emissions modeling assumptions is included in Chapter 5.

Experience in the 2000-2001 market crisis underscored the risk of inadequate reserve margins and exposure to short-term spot markets. Since then, oversupply conditions in some regions of the west have illustrated the high cost of building or acquiring resources in excess of consumers' needs. Clearly a careful balance must be struck in choosing an appropriate target for margin of resources over demand, a target that minimizes the risk of market price exposure and supply interruption on the one hand and minimizes the high cost of excess capacity on the other.

Equally important, a balanced exposure to the wholesale marketplace must be sought, one that utilizes economic opportunities to lower portfolio costs while also avoiding undue exposure to market price risks. Fortunately, the evolutionary trend of the marketplace is in a direction that supports this balancing role. This trend includes the return of medium-term trading liquidity that offers a wider and more competitive range of purchase alternatives to supplement resource portfolios. Also supportive is the repositioning of the merchant generation sector towards long-term transactions and competitive acquisitions.

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

Integrated gasification combined cycle (IGCC) generation offers a potential resolution to the coal-gas tradeoff. However, IGCC presents its own technological uncertainties. IGCC has only a limited operating history and has not been applied commercially in the U.S., although two subsidized projects have been in operation since 1996. It is not considered a commercially mature technology and therefore its future cost and performance is more uncertain than other more established alternatives. Indeed, estimates of the future cost and operating characteristics of IGCC technology have shifted during the preparation of this IRP (as described in Chapter 6). These shifts are a clear indication that IGCC assumptions must be viewed as a moving target as the technology continues to mature.

Nevertheless, IGCC technology is expected to have a stable fuel cost from utilizing coal and also lower air emission rates for SO_2, NO_X and mercury (Hg) compared to conventional pulverized coal. IGCC's net combustion efficiency is marginally better than pulverized coal. Therefore, these plants are projected to emit CO_2 at a pound per kilowatt-hour rate that is about 10% better than conventional coal generation, but this is still about twice the rate of gas fired CCCT generation.

Significantly, though, IGCC has the potential to capture CO_2 emissions more efficiently than conventional coal generation. This is because CO_2 can be removed from the synthesized gas prior to combustion in the IGCC process. In contrast, proposed methods for carbon capture from CCCT and conventional coal generation must capture CO_2 from the combustion exhaust.

To reduce net greenhouse gas emissions in actuality, CO_2 must also be sequestered or disposed of after it is captured so as not to re-enter the atmosphere. The cost of transporting CO_2 in dedicated pipes and injecting into favorable geological formations (one method of sequestration under consideration) is estimated to be in the range of $10/MWh, over and above the cost to capture. This cost could vary significantly by location and is an estimate without the benefit of extensive commercial experience.

In all cases, CO_2 capture and sequestration add additional and potentially high cost to generation alternatives. The various CO_2 capture and sequestration technologies are still in the research and development stage and not proven on a mature, commercial scale. As such, they also contribute technology uncertainty to future resource choices.

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

THE NEW IRP IMPERATIVES

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

These risks and opportunities place new demands on PacifiCorp's IRP methods and processes. The analytical approach behind this IRP moves towards addressing those demands. Improvements incorporated into this IRP include a simulation approach that allows the performance of resource portfolio alternatives to be compared over a number of possible future conditions. This methodology provides an examination of both the expected future costs and the risks of future outcomes. It also allows an examination of the tradeoff between cost and risk inherent in resource planning choices. This IRP also emphasizes resources within the context of portfolios, since a diverse portfolio is a well-known means of managing risks. Alternative portfolios have been analyzed under a range of assumptions to test their sensitivity to natural gas price and CO_2 cost uncertainties.

CONCLUSION

As described in this chapter, the competitive energy market presents PacifiCorp with the prospect of continued price volatility and risk, and significant uncertainty affecting future resources. Although the risks from exposure to these uncertainties cannot be eliminated, the IRP will help to identify and manage these risks through the choice of new resources and by guiding PacifiCorp to an appropriate margin of resources over expected demand. This Integrated

Resource Plan provides analysis leading to a comprehensive portfolio and strategy for PacifiCorp supply acquisition that balances low cost with risk.

2. 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.

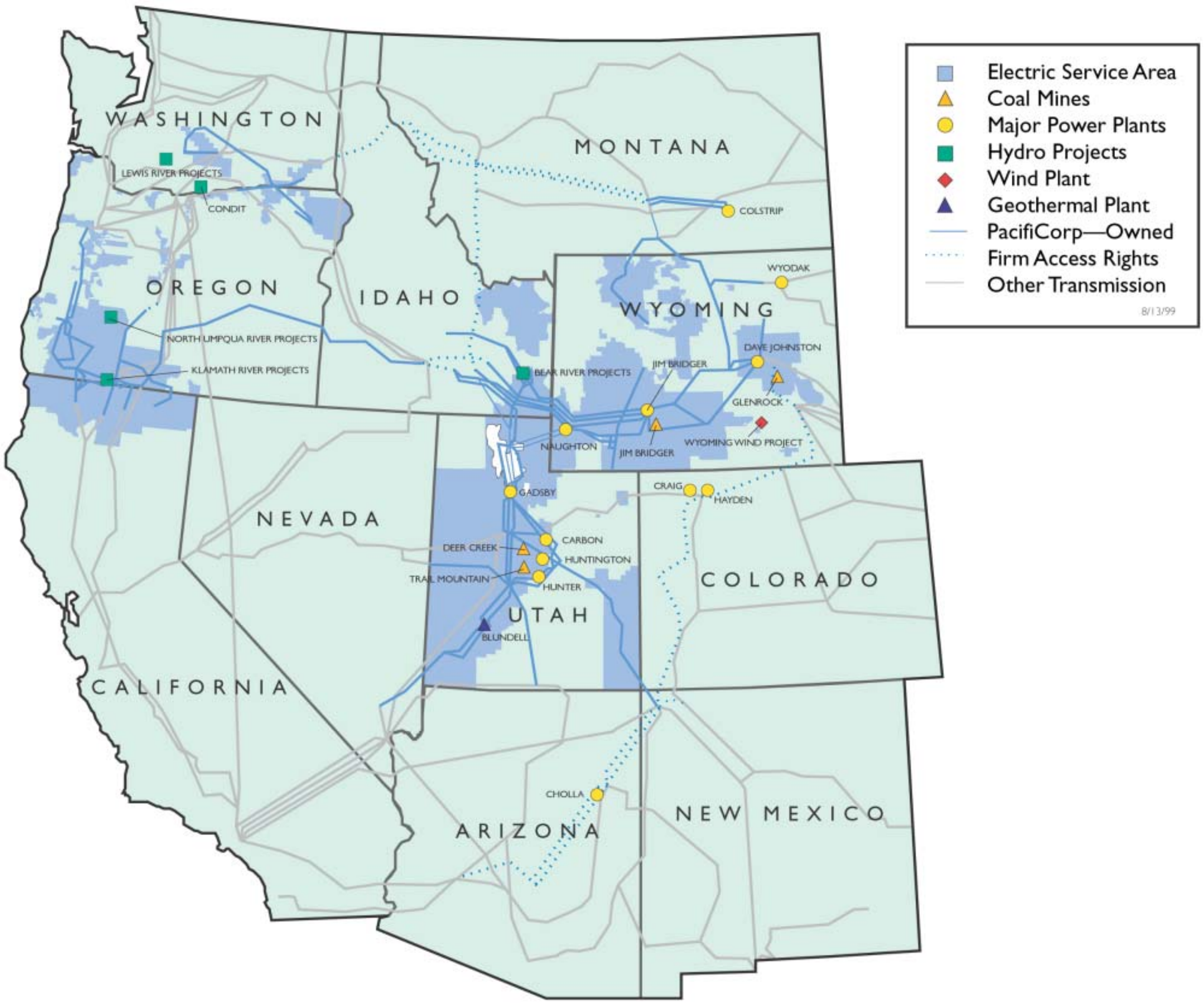
PacifiCorp is subject to comprehensive regulation by the Securities and Exchange Commission (the "SEC"), the Federal Energy Regulatory Commission (the "FERC") and other federal, state and local regulatory agencies. These agencies regulate many aspects of PacifiCorp's business, including customer rates, 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	**2004**		**2003**		**2002**	
(Thousands of MWh)						
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.

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.

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:

<u>New Resources</u>

- 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

<u>Existing Resources</u>

- 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.

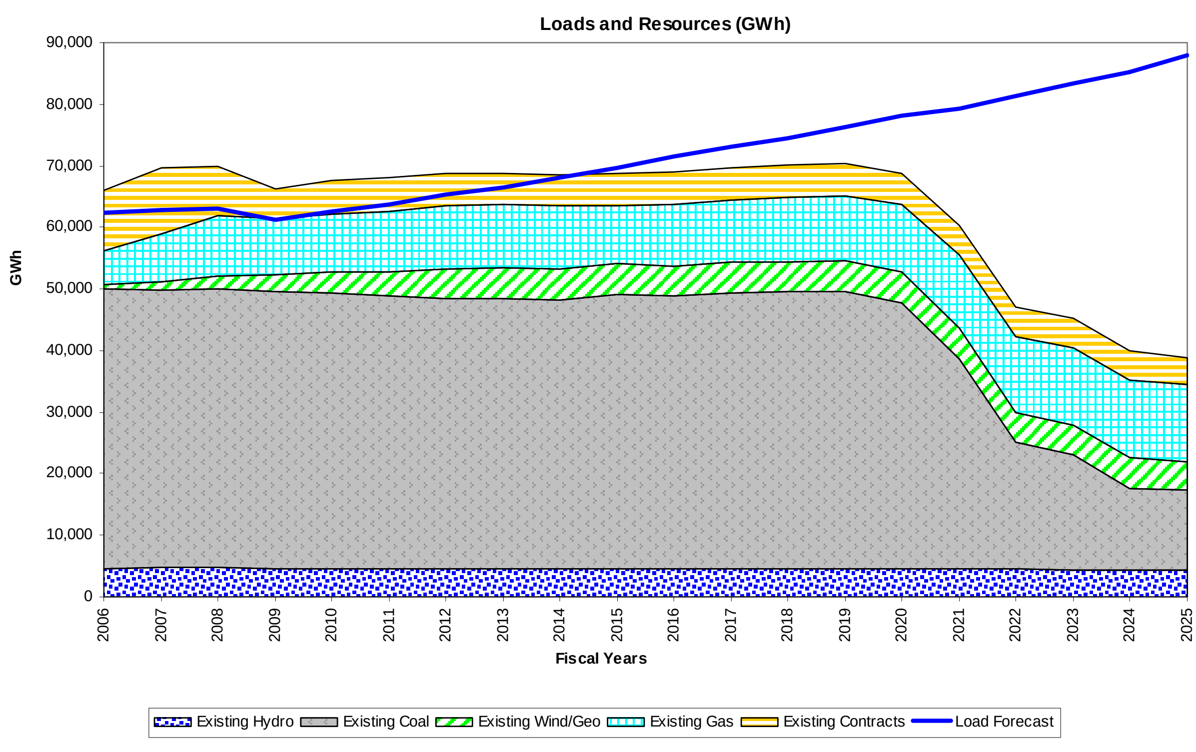
Existing Resources
The first resource group in the resource base data is referred to as Existing Resources. These are defined as resources currently in operation or for which procurement contracts have been signed.

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.

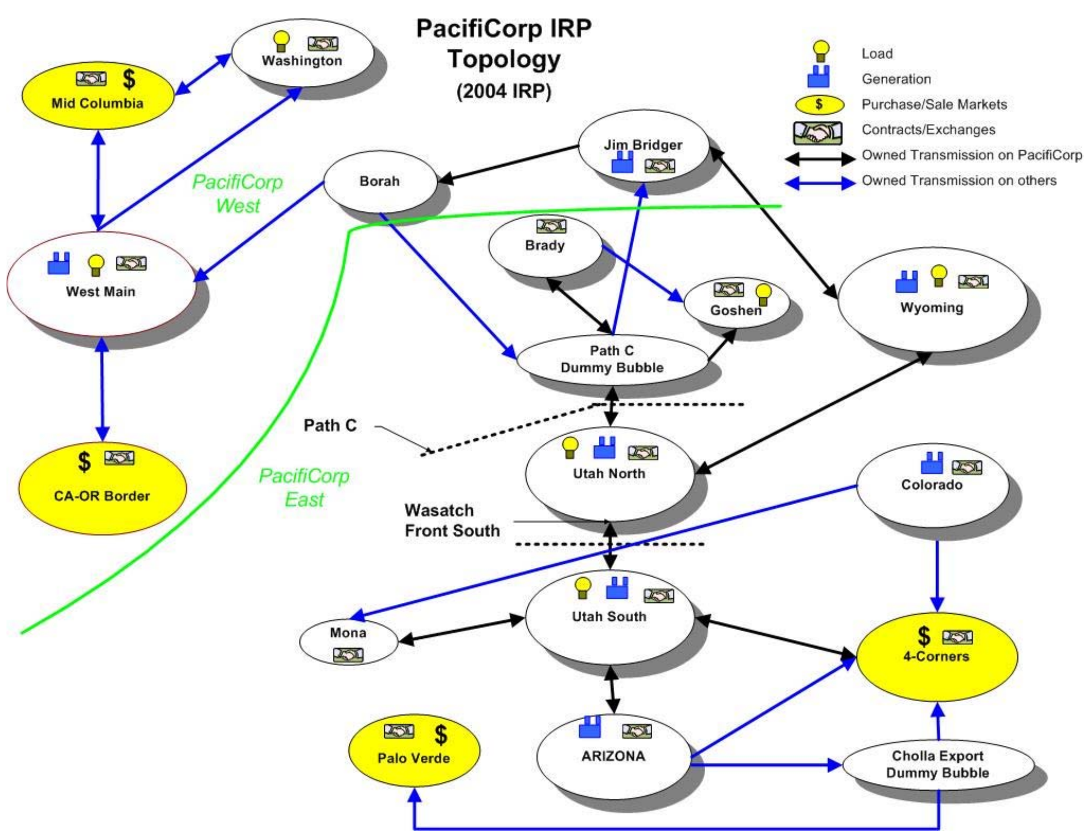
Most Regional Planning Councils across the country have set planning margin and reliability targets. WECC and SERC are the only Councils without either specified resource adequacy criteria or planning reserve margin. The most common resource adequacy criteria are the 1-in-10 year Loss of Load Probability (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

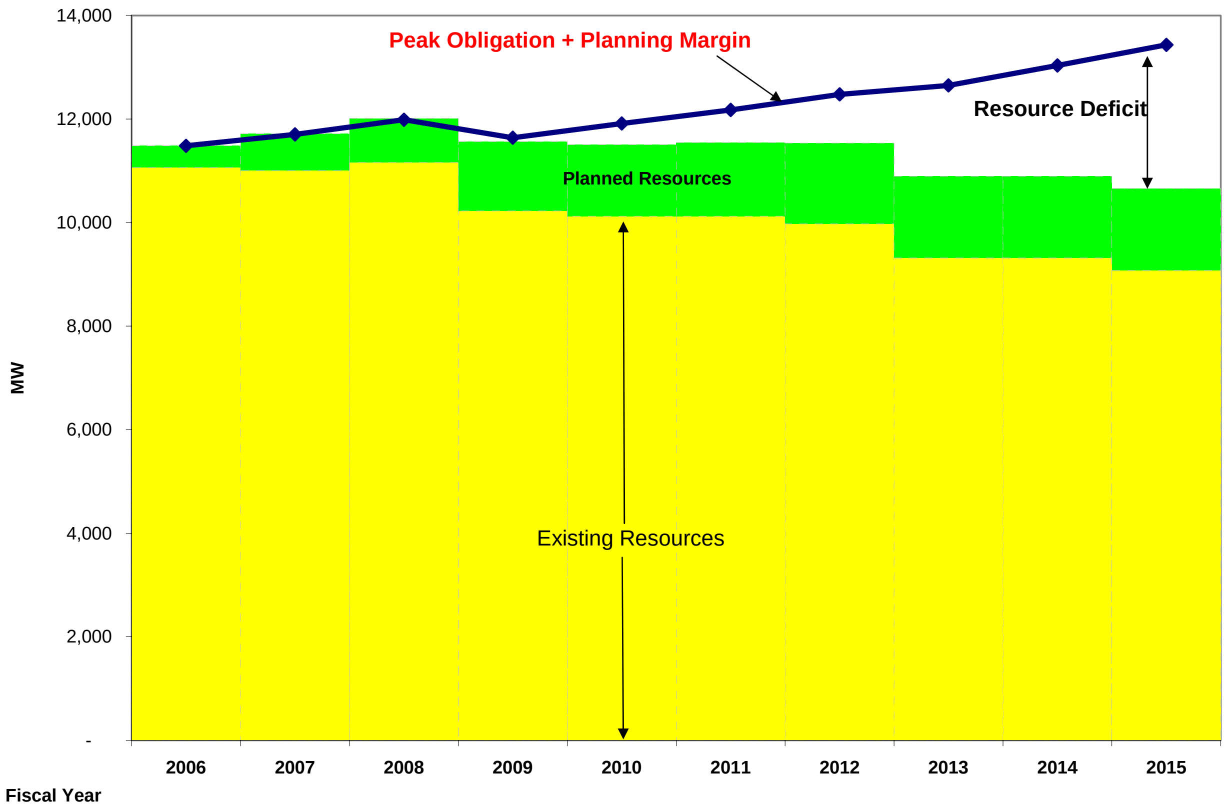
Capacity Charts show the peak obligation (load plus sales) plus the planning margin requirement as compared to the available resources for the peak load hour. They were constructed by determining the system coincident peak hour for each of the first ten years of the planning horizon (FY 2006-2015), and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

Existing Resources = Thermal + Hydro + Purchases + Interruptible + 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.

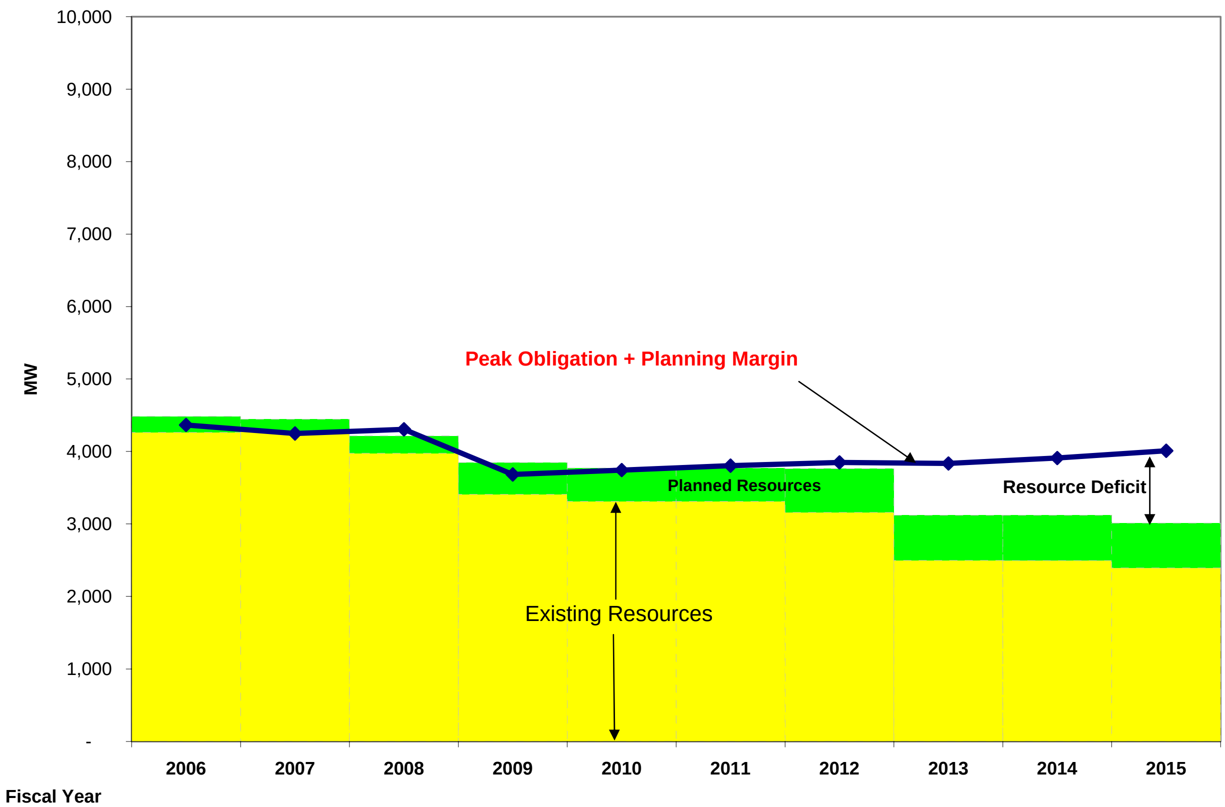
Figures 3.3 through 3.5 present the various capacity charts developed for the Load & Resource Balance. In the System and West Capacity Charts there are a few noticeable declines in resources and loads in the 10-year period mostly caused by the expiration of existing contracts. For example in FY 2008 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



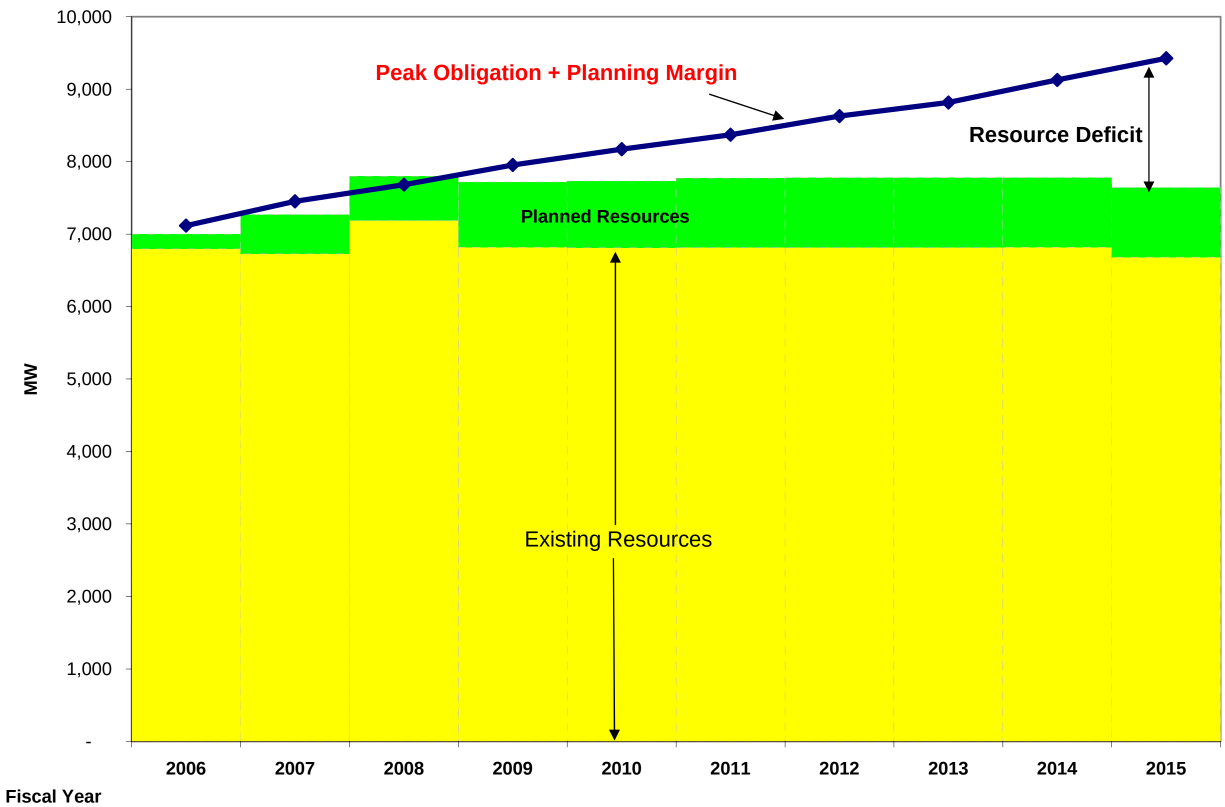
Resources	11,484	11,714	12,013	11,566	11,526	11,546	11,537	10,897	10,895	10,657
Obligation+15%	11,485	11,701	11,988	11,639	11,916	12,177	12,478	12,650	13,035	13,434

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

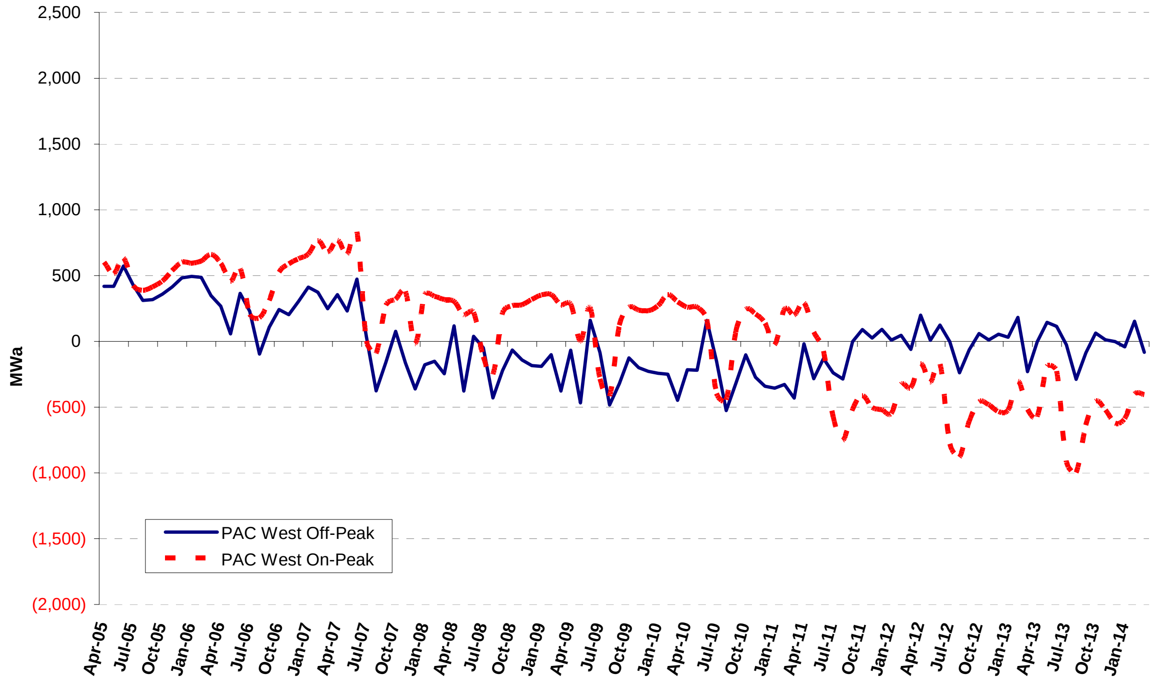
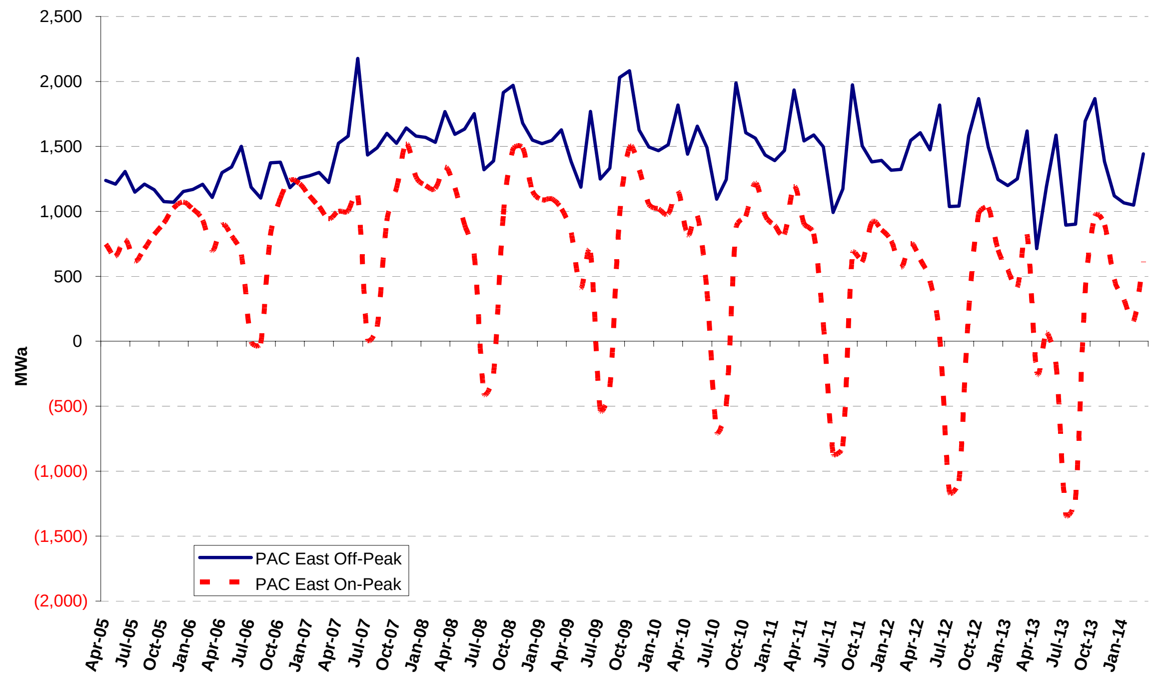


Figure 3.7 – East Energy Curves



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.

4. RISKS AND UNCERTAINTIES

INTRODUCTION

Electric utilities operate in a sometimes uncertain and volatile environment. The western energy market conditions of 2000-2001 described in Chapter 1 illustrate this. In addition, there are increasing potential risks associated with fuel, either in terms of supply, transportation or emissions mitigation risk. Educated foresight about fuel-associated risks, combined with the awareness of recent market events, underscores the importance of risk management.

Risk analysis, or appropriate risk considerations involved in cost/benefit analysis, is a standard corporate practice. Risk consideration is an integral part of PacifiCorp's electricity system planning process. In other words, recognition of the potentially different outcomes, due to the uncertainty about the future, is paramount. However, general techniques for effectively incorporating risk analysis into utility resource plans have been more elusive. This chapter discusses risk in general and describes the techniques PacifiCorp employed to incorporate risk analysis into its Integrated Resource Plan.

CLASSIFICATION OF RISK

Risk is defined as a measure of uncertainty. Not all risks are assessed in the same way. Some risks may be modeled as an uncertain deviation from an average. For example, the Palo Verde electricity price realized next summer will most likely vary from expectations today (i.e., the forward price or a fundamental price forecast). This type of risk is known as Stochastic risk and is relatively new in the evaluation of risk in the planning process. Once computers reached a certain level of sophistication it became possible to vary inputs based on a probability distribution which led to results following a distribution and allowing statistical analysis of these results. This variability and the associated impact on PacifiCorp's system operations can be quantified by applying stochastic modeling techniques described in Appendix G.

Another type of risk which may be modeled is Scenario risk. This type of risk consideration has been analyzed longer than Stochastic risk. With a scenario different from the expected outcome there is typically a large and consistent departure from the mean value associated with a fundamental shift in a belief about a modeling assumption. This different scenario has at best a subjective probability assigned to it and has the limitation of little, if any, formal statistical analysis. Scenario risk is often associated with changes in fuel prices. In the case of the IRP process, PacifiCorp assumes Scenario risk around gas price and CO_2 emissions limits, which impacts fuel and market prices.

Lastly, some risks are not able to be modeled in the standard sense. If a change is introduced in the way the electric utilities do business, e.g. participation in a Regional Transmission Organization (RTO) or other transmission entity, the model itself needs to be modified to account for the structural changes. Since the details of such changes are largely unknown, it is not possible at this time to quantify the related impact with mathematical modeling techniques.

Accordingly, the risks faced by PacifiCorp can be sorted into three general categories: Stochastic, Scenario and Paradigm risks.

Stochastic Risks

Stochastic risks are quantifiable uncertainties for particular variables. From their historic values, parameters can be numerically generated to produce a known statistical process that represents their variability. Another name for this statistical process is a stochastic process, or the way in which values change in an uncertain manner over time.

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

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

Explained by a known statistical process with a constant mean for a period of time, Stochastic risks naturally lend themselves to simulation. As such, their variability is captured in the IRP modeling through Monte Carlo simulation of the parameters of the stochastic process and the stochastic analysis results are reported in Chapter 8. Appendix G contains detailed information about the risk parameters.

Scenario Risks

Scenario risks are also parameter driven. However the parameter variability 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. In the case of changing Scenario risks, the time evolution of critical inputs, e.g., gas and electrical prices, takes a distinctly different path, rather than fluctuating around an expected value. This risk category is intended to embrace abrupt changes in the risk factors, such as introduction of high CO_2 emissions allowance charges. The probability of high CO_2 emissions allowance charges cannot be determined with a reasonable degree of accuracy. Therefore, a scenario of this occurrence is created without applying a probability to it. With assumed values (as opposed to simulated values) portfolios can be analyzed for their sensitivity to a specific Scenario risk.

The Scenario risks addressed in the IRP are listed below. These scenarios were analyzed in the IRP model, and the assumptions and results are described in Chapter 8.

- Values for prospective CO_2 emission allowances can be assigned. For example charges in the model are assumed to equal \$8/ton above the year 2000 cap. This base case CO_2 emissions allowance charges are consistent with the natural gas and power prices used in the deterministic evaluation of this IRP. The base case assumes that a cap and trade market develops in CY2012 at \$8 per ton in 2008 prices in response to limits set on CO_2 emissions. It is further assumed that there is a 50% probability of the CO_2 limit starting in CY2010 and a

75% probability starting in CY2011. Stress cases also modeled the impact of varying market responses to CO_2 limits with additional allowance rates ($0/ton, $10/ton, $25/ton and $40/ton in 1990 dollars) to be in compliance with Oregon Order 93-695 dated May 17, 1993. The starting point of the stress cases is also assumed to be graduated starting in FY2010 as in the base case.

- Since the base case gas forecast was developed in June 2004, prices have increased. A preliminary gas forecast planned for use in PacifiCorp's December 31st 2004 official price forecast for CY 2005 to CY 2015 was used. This forecast, derived from PIRA Energy's most recent long term natural gas price forecast, is on average $2.27/MMBtu higher at Henry Hub than the gas forecast used in the IRP base case. Therefore, to create a high gas sensitivity case, this price forecast was used as the starting point and was increased by 10%. In addition, a real escalation rate of 0.5% per year beginning in CY 2016 was used. The long-term real escalation adjustment reflects the possibility of gas demand outpacing gains in production in the long term. The high gas price forecast was then used in the MIDAS model to generate a consistent "High Gas" power 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 associated risks—which can imply both positive and negative implications—are typically addressed outside of the model and cannot be summarized by a simple series of metrics. The assessment of Paradigm risks is usually qualitative rather than quantitative.

An example of a paradigm shift would be a fundamental change in the responsibility for the operation of the regional transmission grid and its related wholesale markets, such as the introduction of an independent regional transmission entity. The current proposal for such a regional transmission entity covering PacifiCorp's transmission footprint – Grid West – calls for a staged approach which would begin by consolidating major control areas, and establishing real-time markets, an independent market monitor, and a centralized planning function with limited backstop authority. Such an innovation would introduce fundamental changes in the use of the existing transmission grid, and would facilitate the process for the planning and implementation of new transmission. When the details of changes such as those in this example are not specified, paradigm shifts do not easily lend themselves to quantitative analysis. Such changes to fundamentals generally defy reasonable approaches to numerical representation until they are more fully developed.

While not explicitly modeled, the potential impacts of Paradigm risks cannot be ignored. Attempts are made to create a plan with the flexibility to respond to changes in Paradigm risks. In some instances, assumptions are explicitly modeled to impute additional flexibility. Despite these efforts, Paradigm risks, as they arise, will ultimately require a well reasoned response developed in conjunction with PacifiCorp, its regulators and the public.

DISCUSSION OF PARADIGM RISK

The primary paradigm shift considered in this IRP is the introduction of Grid West, a regional transmission entity. A discussion of Grid West, treatment of Grid West in the 2004 IRP, and its potential impact follows.

Regional Transmission Entity

PacifiCorp, in conjunction with nine other utilities, is seeking to form Grid West, a new independent, non-profit corporation that would manage certain operational functions of the regional transmission grid and plan for necessary expansion. Currently there are 10 members ("filing utilities") of Grid West and they include:

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

In early December 2004, the filing utilities, in collaboration with regional stakeholders, adopted new bylaws for the interim board of Grid West. In early 2005 the activities for Grid West include continued development of the Regional Proposal, opens the process for parties in the region to become members of the new organization and initiates the search for candidates to be elected as independent trustees on a new five-person developmental board of directors.

Going forward, PacifiCorp will focus on working with the interim board of Grid West and the region's stakeholders on the design details, and influencing the acceptance of Grid West as a workable and beneficial market design framework for its members. Assuming continued regional support, the filing utilities also plan to work with the proposed Grid West independent board of trustees to develop transmission agreements and develop a Grid West tariff in late 2005 or early 2006. In addition, the filing utilities have entered into a Memorandum of Understanding with the other two potential Western RTOs, namely WestConnect and the California Independent System Operator, and will work on inter-regional issues through this agreement.

Potential Impact

There are many substantive impacts expected from the operation of Grid West. First, the entire existing transmission grid will be operated more consistently and comprehensively as one system leading to an increase in efficiency and reliability of the region's transmission system. In this regard, certain ancillary services will be acquired and provided on a more systematic basis allowing the most economic generation to be used to meet certain load requirements over a wider geographic area.

Additionally, the planning, financing, cost allocation, and cost recovery standards and methods associated with construction of new transmission assets will be improved. These improvements should clarify the decision process for identification of new transmission expansion, help alleviate regulatory uncertainty, and streamline the construction of regional transmission, allowing broader fuel and geographic diversity in new resource additions.

Treatment in the IRP Models

PacifiCorp supports the development of Grid West and expects to make a final decision whether to sign a transmission agreement with Grid West in CY2007. It is PacifiCorp's belief that a properly developed Grid West can increase the efficient use of the transmission grid, improve reliability of the grid, and increase the likelihood of needed transmission expansion occurring.

The impacts of Grid West have not been explicitly modeled in the IRP, but are considered in the IRP Action Plan. Therefore, the models continue to assume no changes in the current use of the existing transmission system—and are even more conservative in that only firm transmission rights are modeled. As more day-one details are developed for Grid West, they will be incorporated in more specificity in the next IRP.

<u>Other Paradigm Risks</u>

Several other Paradigm risks are possible during the planning horizon. These risks include, but are not limited to, the following:

- Changes in state or federal imposed mandates, e.g., renewable portfolio standards, multi-pollutant legislation
- Deregulation similar to SB 1149 in Oregon occurring in the states served by PacifiCorp.

RISK ASSESSMENT

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

CUSTOMER AND SHAREHOLDER RISKS

Stakeholders requested during the public input process for the previous IRP, and IRP standards and guidelines require, that PacifiCorp provide a discussion of the risks borne by customers and those borne by shareholders[9]. This section discusses such risks.

The distribution of risk is not a simple matter. This discussion will be based on the assumption that the risk of an unanticipated change in cost is borne in part by customers through rate changes that may not capture the full cost change. As a result the part of the unanticipated cost

[9] Standards and Guidelines issued by the Utah Public Service Commission include a requirement that the IRP, "Identify which risks will be borne by ratepayers and which will be borne by shareholders."

change that is not captured in customer rates is borne by the shareholder. Ultimately, shareholders are at risk for the difference between PacifiCorp's actual costs and the amounts included in rates.

Associating risks with ratemaking reflects simplifying assumptions. If rates increased substantially reflecting a large cost increase, customers would likely respond. Similarly if PacifiCorp did not recover a large cost increase in rates, PacifiCorp's ability to finance its operations may be impaired and its cost of capital may increase. These would, in turn, create risks for customers. Greater risk harms both customers and shareholders, and that is why this plan focuses on reducing risk as well as reducing cost.

The degree to which a cost change is reflected in rates is itself not a simple matter. Ratemaking treatment varies among states, changes over time, and can depend on the magnitude of the cost. The remainder of this section discusses ratemaking mechanisms that affect the extent to which costs are included in rates and therefore borne by customers.

Standard Ratemaking

PacifiCorp provides cost-based electric service to retail customers. The IRP addresses the resource actions required to meet this obligation. The IRP exclusively focuses on resource actions required to meet PacifiCorp's obligation to serve retail customers. The IRP does not contemplate resource additions or market activities directly benefiting shareholders or parties other than retail customers in existing jurisdictions served by PacifiCorp. As a general matter, PacifiCorp believes that it should have an opportunity to recover all of the costs that it prudently incurs to serve its retail customers. The use of a detailed planning process, such as the IRP, is part of this prudent utility operation.

In a standard rate case, many elements of expense and certain other factors are based on expected or normalized amounts. Elements of revenue requirements that are typically normalized include forecasts of:

- Loads
- Wholesale power prices
- Hydroelectric availability
- Thermal plant outage rates
- Volumes of wholesale purchases and sales
- Fuel costs
- Operating and maintenance expenses

Expected changes in these elements are typically reflected in normalized revenue requirements and, to that degree, are borne by customers. Unexpected variations in these elements are typically not reflected in rates and, to that degree, are borne by PacifiCorp unless specific regulatory mechanisms provide otherwise. Many Stochastic risks quantified in the IRP translate into normalization risks in ratemaking. Consequently, over time, these risks are shared between customers and shareholders. Between rate cases, shareholders bear these risks. Over a period of years, changes in cost will be reflected in rates and customers will bear the risk.

Asset-related costs such as depreciation and capital costs are treated somewhat differently than expenses in standard ratemaking. An asset is typically not included in the determination of revenue requirements until the asset is in service and the actual cost is known, although Future Test Years in some states are changing this principle. The actual cost of a generating asset may vary from the cost assumed in this plan. Commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risks associated with unexpected changes in capital cost are borne by shareholders. To the extent that capital costs vary from those assumed in this plan for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

For PacifiCorp, ratemaking involves the allocation of system costs to individual states. In the past, states have disagreed about the allocation and appropriateness of certain costs. Such disagreements could result in a failure to include even expected, prudent costs in rates. The Multi-State Process has been addressing this issue.

Very Large Unexpected Costs

Events in 2000 and 2001 put standard ratemaking mechanisms under substantial pressure. Unexpected increases in expense were large enough that customers were placed at risk even though the standard regulatory model would have caused shareholders to bear the costs. Many utilities were downgraded below investment grade and some went bankrupt, with obvious costs to their shareholders and associated costs and risks to their customers.

The ratemaking process responded to these very large unexpected cost increases on a case-by-case basis. Some of PacifiCorp's jurisdictions allowed PacifiCorp to accumulate a portion of its excess costs and recover them over a period of time. Some jurisdictions did not allow such recovery on the basis that the standard regulatory model did not provide for it. Each jurisdiction used a somewhat different approach to the problem.

One potential source of very large future costs that has been discussed by stakeholders in the IRP public input process is government action related to CO_2 emissions. Government action may include a CO_2 tax, restrictions on CO_2 emissions, a combination of both, or neither. It is difficult to discuss these costs without knowing their circumstances or magnitude. However, PacifiCorp provisionally offers the following principles regarding recovery of costs related to CO_2 emissions at its generating plants:

- PacifiCorp should have an opportunity to recover its prudently incurred costs.
- The costs associated with CO_2 emissions are not imprudent. PacifiCorp's coal-fired power plants have provided customers with low-cost electricity for decades. Since customers have received the benefit of the plants, they should also expect to pay the costs.
- If a new generating plant were to become uneconomic to some degree as a result of government action regarding carbon emissions, that plant would not be imprudent. At this time, the potential costs of government actions regarding CO_2 emissions are highly uncertain. This IRP evaluates new generating resources assuming a CO_2 allowance charge of $8 per ton.
- The costs of mitigating carbon emissions and sequestering carbon should be recoverable from customers.

- Individual state statutes or regulations that create costs related to CO_2 emissions are a form of Portfolio Standard. The cost of complying with such state requirements should be assigned to the state enacting the requirements.
- In all cases, rate making treatment of PacifiCorp's plant investments should be based on the "Prudent Man" rule. That is, an investment should be judged prudent and its costs recoverable as long as PacifiCorp can meet its obligation to show that it made the investment decisions by carefully and consciously considering and evaluating all options and selecting the option that offered customers the best long-run cost-risk balance given what was known and knowable at the time the decision was made. This is not a standard of perfection. It recognizes that many non-commensurable components of each option must be weighed in the process and the careful judgment of PacifiCorp decision makers must be applied. A pure and simple lowest possible cost decision does not necessarily meet the prudence test. It also recognizes that prudent decision can become non-optimal as reality plays out over time. Regulator's rate making decisions must be based on the prudency standard as laid out above.

PacifiCorp expects that specific regulatory treatment of costs associated with CO_2 emissions will be discussed at the time that any such costs become known.

Power Cost Recovery Mechanisms

Following events in 2000 and 2001, PacifiCorp has requested or is in the process of requesting power cost recovery mechanisms in many states. These mechanisms would share power cost changes, positive and negative, beyond a certain threshold between customers and shareholders. This approach would be a departure from the current regulatory approach of setting all anticipated net power costs in rates. Such mechanisms can provide potential benefits for both groups. The Wyoming Public Service Commission has approved a power cost pass-on request filing and PacifiCorp continues to develop mechanisms that may be acceptable in Wyoming and its other jurisdictions.

Distribution of Risk Among Customer Classes

All customer classes share the same fundamental interest in electric service, i.e., that it be reliable with low and stable costs. In general, the risks associated with resource planning affect the various customer classes in the same way. An exception may be nonresidential customers in Oregon who choose Direct Access service. These customers choose to accept market risks instead.

Conclusion Regarding Customer and Shareholder Risks

Customers receive the benefit of a successfully implemented IRP and customer interests should drive the choice of resource strategy. The IRP should seek the best balance between cost and risk to customers. Options with lower risk tend to impose higher fixed cost "insurance premiums." The IRP risk analysis is primarily focused on striking the right balance to deliver value for its customers but not at the expense of shareholders.

Shareholders should have an opportunity to recover their prudently incurred costs. Commissions may need to consider ratemaking mechanisms to ensure that PacifiCorp is not financially harmed by resource choices that benefit customers.

CONCLUSION

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

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

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

5. THE IRP ANALYTICAL APPROACH

INTRODUCTION

The main analytical objective of the IRP is to determine the Preferred Portfolio, which is the resource portfolio with the best balance of cost and risk. The analytical process does this by systematically comparing the cost (measured as the Present Value of Revenue Requirement, or PVRR) and performance (risk or variability of PVRR) of various resource plans. This chapter highlights the analytical framework used for accomplishing this objective. The information drawn from this analysis, summarized in Chapter 8, will help identify near-term actions consistent with the best-performing portfolios.

IRP MODELING PROCESS

Steps in Analysis

The IRP modeling process consists of nine distinct steps. Refer to Appendix H for a discussion of the models used in the modeling process. A brief summary of the nine modeling steps is provided below. A more detailed discussion of each step follows.

- **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.

Step 1: Portfolio Development

Portfolio Development is the first step in the analytical approach. PacifiCorp employs a portfolio selection process that revolves around the development and subsequent analysis of complete portfolios consisting of base resources (Existing and Planned) along with capacity additions to address expected short positions.

Starting Position

The first step in the portfolio development process is compiling a complete load & resource balance for the PacifiCorp system (See Chapter 3 for details). Yearly deterministic MARKETSYM runs are done for the first ten years (FY 2006-2015) of the 20 year planning horizon. This provides information about how long or short the system is expected to be for the coincident peak hour of each year. In addition, it provides information about the energy balance throughout each of these years.

From this analysis, coincident peak capacity charts are constructed and used to determine the timing and size of resource additions. In addition, net position duration curves and energy curves are used to determine the type of portfolio resource additions.

Resource Options

A list of supply side resources, demand side resources, distributed resources, and transmission options are developed (See Chapter 6 for details on potential resource options). Appendix C contains detailed operational, cost, construction and siting information for each technology considered as a candidate resource for inclusion in portfolios. The information in Appendix C is used as both a source of model inputs, as well as a tool for manually building portfolios.

Portfolio Development Guidelines

The major guideline in the portfolio development process is to build to and maintain a 15% planning margin for the PacifiCorp system. Another important guideline is to develop a range of portfolios reflecting key resource configuration concepts. This includes the resource technology type, such as the impact of using Combined Cycle Combustion Turbine (CCCT) versus Simple Cycle Combustion Turbine (SCCT) technology. Other concepts include fuel type, build timing and location.

There are a number of additional criteria or guidelines to be observed. These include the following:

- Compliant with all federal and state requirements
- Compliant with EPA and other environmental requirements
- To the extent possible, without unduly burdening ratepayers, be consistent with other public policy values that may not necessarily be embodied as a specific regulatory requirement e.g. renewable policies or technology preferences
- Be technically feasible, e.g. based on tried and proven technologies

- Resources can be acquired in time to meet load requirements taking into account resource procurement considerations
- Environmental implications associated with the potential options must be realistic

To get started, a Reference Portfolio is constructed. This portfolio serves as a starting point for the development of additional portfolios and is based on experience. Subsequent portfolios are developed by varying one element of the Reference Portfolio. An example of this would be to test what the result would be if an IGCC plant was replaced with a Pulverized Coal plant of similar capacity. By having the two portfolios differ by one element, comparative analysis of simulation results is greatly simplified.

Build Portfolios

A spreadsheet tool was developed by PacifiCorp for building portfolios. This tool incorporates the results of the load & resource balance and the resource options to show the build pattern and sizes of portfolio resources subject to the 15% planning margin constraint. An example is given in Table 5.1.

Table 5.1 – Portfolio Build Table

Resource	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
CCCT	-	-	-	1,000	1,000	1,000	1,500	1,500	2,000	2,000
SCCT	-	-	175	175	350	350	350	350	350	525
Coal	-	-	-	-	-	-	600	600	600	600
Wind	-	-	50	50	50	300	300	300	300	400
Total Additions	-	-	225	1,225	1,400	1,650	2,750	2,750	3,250	3,525
Total Resources	10,000	10,000	10,225	11,225	11,400	11,650	12,750	12,750	13,250	13,525
Obligation (incl. 15% PM)	9,200	9,400	10,200	11,200	11,400	11,600	12,500	12,700	13,000	13,500
Derived Planning Margin	25.0%	22.3%	15.3%	15.3%	15.0%	15.5%	17.3%	15.5%	17.2%	15.2%
						Derived Margin (FY2008-FY2015) =				**15.8%**

The top portion of each portfolio table contains the capacities of various resources for each of the first ten years of the planning horizon. In the next three rows are cells that calculate the annual net position and planning margin that results from the resource additions. Thus, by adding the appropriate resources, portfolios can be quickly developed that fill the short position for each of the ten years.

In conjunction with the manual development process, the Capacity Expansion Model is used for validating the manually created portfolios. The CEM is a linear programming-based portfolio filtering tool that is still in the development stage and has not been fully validated. After full validation, it may be used in the next IRP as a primary vehicle for generating alternate portfolios for detailed simulation. It will also be used to inform the Action Plan Path Analysis detailed in Chapter 9.

Chapter 7 documents all the portfolios developed for simulation and analysis.

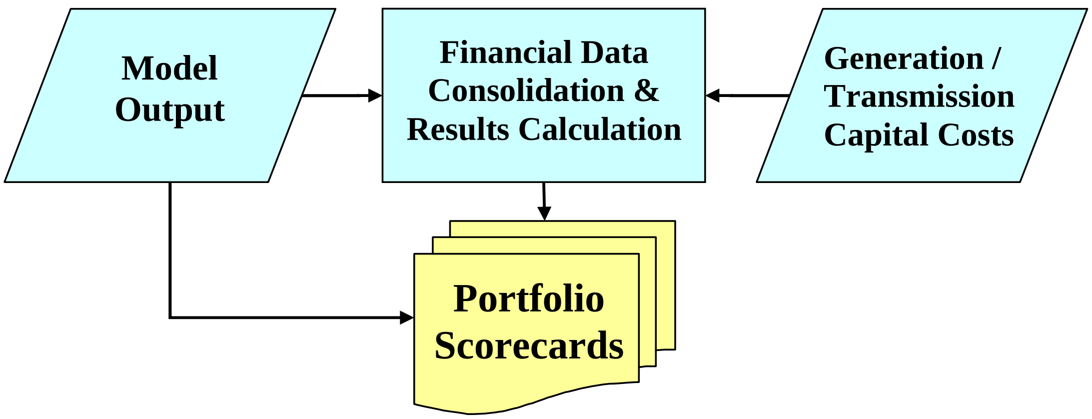
<u>Step 2: Operational Simulation</u>

With candidate and stress case portfolios assembled, PacifiCorp simulates the combined hourly operation of its system and the capacity additions using the MARKETSYM model. Details regarding the MARKETSYM model can be found in Appendix H.

For each portfolio, the operational information for each capacity addition is entered as well as any necessary changes to the system topology to reflect transmission upgrades required by the new resources (see Chapter 3). The model is then allowed to simulate the period from April 1, 2005 through March 31, 2025 (FY 2006 to FY 2025). This results in a detailed simulation of the dispatch of the existing and new resources to meet forecasted load and sales obligations according to the transmission constraints defined by the system topology.

Each simulation results in a breakdown of variable costs and emissions levels for each new and existing resource. The breakdown also includes such things as unit capacity factors, variable contract costs, and market purchases & sales. These factors provide valuable information as to the financial performance of the portfolio. As shown in Figure 5.1, the variable cost results of each portfolio as well as other operational results are extracted from MARKETSYM outputs and entered along with the capital costs (both generation and transmission upgrades) into the Consolidated Model which is discussed next.

Figure 5.1 – Consolidation of Model Results



<u>Step 3: Cost Analysis</u>

The Consolidated Model is a tool that combines the operating cost results from MARKETSYM with the revenue requirement of new capital additions to provide a PVRR projection for each portfolio. This consolidation process is illustrated in Figure 5.1. The net variable cost from MARKETSYM includes system costs for fuel, variable plant O&M, unit start-up, market contracts and spot market purchases and sales. The variable costs included are not only for new resources but include existing system operations as well. Additional costs calculated in the Consolidated Model (if applicable to the portfolio), include DSM costs, renewable green tags, production tax credits, emission allowance costs or credits, and all the revenue requirement costs associated with adding incremental investment in new resources and new transmission. PVRR is the combination of system wide variable operating expense and the capital costs of new resources and transmission additions.

All annual values are determined in nominal, or escalated, dollars. The revenue requirements for the new resource and transmission capital additions are included as escalated "real-levelized" revenue requirements (See Appendix O for details on real levelization). The Consolidated Model does not include certain costs that are deemed to be common to all IRP portfolios. Excluded costs are the capital and fixed O&M costs of existing resources, Clean Air Initiative (CAI) costs, hydro relicensing costs, and other non-electricity supply costs such as distribution, transmission and general plant capital and fixed operating costs.

The Consolidated Model calculates the PVRR of the annual combined revenue requirement for the 20-year analysis period (FY 2006 to 2025) for comparison among portfolios. Using the Consolidated Model of each portfolio, the PVRR along with several other cost metrics and operational parameters are linked to the Portfolio Scorecard to facilitate side-by-side comparisons.

Customer Impacts

In addition to the PVRR calculation, the total costs of each candidate portfolio on a per-MWh basis are calculated to assess customer impacts since the cost per unit of energy better represents the impact on customer rates than the total PVRR. It also helps reflect the rate changes, which might be required moving from one year to another. This calculation, while providing an indication of rate direction, does not represent rates fully allocated by state and customer class; rather, it considers only the incremental costs of the new resource additions and variable operating costs of generation supply.

Environmental Externalities

Environmental externalities are quantified by the emission allowance impacts to the portfolios which are calculated by modeling cap and trade emissions programs for NO_X, SO_2, Hg and CO_2. Each ton of pollutant emitted above the annual system allotment is charged a $/ton rate. If total system emissions are below the defined system cap, a credit is applied to the portfolio. Allowance values for each pollutant are included in Appendix C.

Allowance trading markets for NO_X and SO_2 currently exist. Although carbon emissions are not currently regulated, PacifiCorp has modeled a future carbon regulation scenario using the proposed legislation of Senators Lieberman and McCain for guidance. Their proposed approach limits national emissions in 2010 onwards to 2000 levels. The IRP imposes CO_2 allowance prices reflecting the likelihood of a CO_2 policy that begins in the CY 2010 to CY 2012 timeframe. The base case CO_2 cost is set at an inflation adjusted $8/ton CO_2 (2008$) price. This price level is consistent with the upper range of offsets currently available and with offset costs emerging internationally. In recognition of the timing uncertainty, initial CO_2 costs are probability-weighted. Costs begin to appear in CY 2010, but they are multiplied by a probability of 0.5. Likewise, CY 2011 prices are multiplied by a probability of 0.75. By CY 2012, the full inflation adjusted $8/ton CO_2 cost adder is imposed, growing at inflation thereafter.

If total fleet CO_2 emissions are below the year 2000 level cap, the difference is a credit to the portfolio PVRR. If fleet emissions are above the cap, the portfolio will be charged for each ton emitted above the cap.

Mercury emissions source identification and associated rules are not currently defined or enforced, however, there are several Congressional proposals including the Administration's Clear Skies Act which call for Hg limits imposed under a cap-and-trade structure. This IRP assumes a cap-and-trade policy will most likely begin in CY 2010 with prices based upon PIRA's forecast with a "backstop" price of $35,000/lb, adjusted for inflation.

The quantification of air emissions impacts through cost adders is generally recognized as the least ambiguous and least subjective approach to assessing externalities. A full range of other potential impacts, such as those on water supplies; traffic and land use patterns; and visual or aesthetic qualities; critically depend on the specifics of any particular project.

Total Resource Cost

The PVRR measure captures the total resource cost for each portfolio. Total resource cost includes all the costs to the utility and customer for the variable portion of total system operations and the capital requirements for new supply and Class 1 demand side resources as evaluated in this IRP. Utility costs include the capital for new resources and all the variable operating expenses for the system. There are no additional costs to customers modeled other than tariff rates which are a benefit to the utility and therefore negate each other when considering total resource costs. New Class 1 DSM programs as modeled in the portfolios have no participant costs, only utility costs are included in the model. In addition, PacifiCorp has included emissions adders for environmental externalities through modeling emissions cap-and-trade programs. Therefore, the PVRR is the total resource cost.

Step 4: Screening

Screening of the portfolios is facilitated by the Portfolio Scorecard, which provides comparisons of each portfolio's:

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

The Portfolio Scorecard is used for two purposes. The first is to evaluate and compare portfolios in order to further improve them; the second is to narrow the list of candidate portfolios for risk analysis. This portfolio development-simulation-evaluation cycle is iterated to filter out poor PVRR performers and to further refine superior portfolios to optimize favorable characteristics. The end result is a master list of screened portfolios from which to select a group for risk analysis. It should be noted that this group includes not only those portfolios with the lowest PVRR, but also encompasses portfolios with representative resource and risk characteristics. The purpose of including representative portfolios is to avoid an arbitrary cutoff point for portfolio selection where PVRR differences are negligible. Portfolio Scorecards can be found in Appendix E.

Step 5: Risk Analysis

The selected portfolios are analyzed to assess their risk characteristics. Many of the characteristics necessary to simulate operations and calculate net electricity cost are uncertain. PacifiCorp analyzes the effect of varying these Stochastic risks using the Monte Carlo functionality of MARKETSYM. A detailed description of each of the risks and the manner in which they are addressed is available in Chapter 4 and Appendix G. In addition, a number of scenario risk simulations will be run to test some risks deterministically that could not be analyzed using stochastic methods.

Stochastic Risk Analysis

MARKETSYM generates a large number of futures using a random sample of a range of the risk parameters. Parameters are randomly varied based on PacifiCorp's understanding of the correlation among them, as well as their expected values and variability through time. One hundred simulations are run to test the performance over a wide range of environments. This is done to analyze how varying gas prices, electric market prices, loads, hydro availability and thermal outages affect the performance of each portfolio. Allowing all five of these factors to vary at the same time is referred to as the "All-In" analysis. Another set of stochastic simulations is done where only the gas prices and electric market prices are allowed to vary. This is called the "Spark Spread" analysis. The results of both types of simulations are analyzed using a number of risk measures and statistical significance tests which are developed and applied to compose a stochastic risk profile for each portfolio. Refer to Chapter 8 and Appendix G for more detailed discussions of these risk measures.

Scenario Risk Simulations

In addition to modeling portfolio stochastic risks, scenarios on CO_2 emissions and high gas prices are run to test portfolios. Such testing provides performance information over a range of assumed circumstances and allows the modeling of the impact of parameters that do not lend themselves to stochastic analysis. Refer to Chapter 8 and Appendix G for more detailed discussions of the assumptions underlying these Scenario risk simulations.

Risk Evaluation Results

Results from the Stochastic and Scenario risk analyses are summarized to determine which portfolios perform best according to the various risk measures. The end result of this risk analysis is a set of portfolios that are considered superior from a low-cost/low-risk perspective. The results of the Stochastic and Scenario risk analyses are in Chapter 8.

Step 6: Selection of the Preferred Supply Side Portfolio

In this step, the deterministic and risk evaluation results are assimilated along with customer impact results and non-modeling considerations to facilitate the selection of the supply side portfolio that is superior from the standpoint of a low-cost/low-risk tradeoff. The non-modeling considerations include such things as technology risk and PacifiCorp's operating experience with various generation technologies.

Step 7: Selection of the Preferred Portfolio

The preferred supply side portfolio from Step 6 is further refined by including dispatchable, or Class 1 DSM options in the portfolio and simulating the resulting cost impacts. The goal of including Class 1 DSM is to improve the PVRR of the portfolio, which may in part be achieved by deferring higher cost resources.

Class 1 programs are dispatchable and are therefore modeled in a similar fashion to any supply side resource. In the 2003 IRP, Class 1 DSM was manually added as a part of the base case and was therefore the same in every portfolio. For this IRP, new Class 1 DSM programs are treated as potential resource additions. The CEM is used to select the most cost-effective Class 1 DSM resources out of a selection of eight possible programs for the FY 2009 - 2015 period. These programs are added to the preferred supply side portfolio with the intent of lowering the overall PVRR and possibly deferring resources. The delayed time period is chosen as the most realistic range for achieving full implementation of the new Class 1 programs. In this time period, programs will most likely ramp up over several years before reaching full implementation. The Class 1 programs selected for the Preferred Portfolio will then be procured through an RFP process. The most cost-effective proposal will be the most *viable* cost-effective program, and will not necessarily address the same end-use modeled in the Preferred Portfolio. Additional details are provided in modeling results of Chapter 8.

Step 8: Class 2 DSM Analysis

The next step in the process is to evaluate the reduced system operating costs due to a range of Class 2 DSM programs. Unchanged from the method used in the 2003 IRP, Class 2 DSM in this IRP is modeled as planning decrements (reductions) to the load forecast to determine the value of Class 2 DSM to the system. The IRP model is run with and without these DSM decrements. This results in a difference in the revenue requirements for that portfolio with and without the Class 2 load reduction.

To determine the decrement values specific to the PacifiCorp system for various types of Class 2 DSM resources, eight planning decrements of 100 MW at peak, beginning in FY 2009, are modeled. These decrements are shaped to the following loads for both the east and west control areas: residential cooling, commercial cooling, commercial lighting and total control area. The Company will evaluate additional DSM program opportunities by replacing forward-market-price avoided costs used in the traditional DSM cost-effectiveness tests with the shaped decrement values. For such evaluations, the decrement values will be pro-rated to match the load shape of new DSM proposals. The steps of the decrement process are summarized below:

1. Obtain hourly shaping factors for each of the eight decrements.

2. Develop hourly loads for each decrement based on load factor with a peak load of 100 MW. Hourly loads are repeated for each year in the planning period (20 years).

3. Use these hourly loads to reduce (decrement) the load forecast in the MARKETSYM model.

4. Re-run the MARKETSYM model with the revised (decremented) load shape. This involves doing one run for each of the eight decrements.

The DSM Decrements will begin in FY 2009, and be continuous throughout the planning period (20 years). Table 5.2 below provides an overview of the planning decrement design.

Table 5.2 – Planning Decrement Design

Decrement Size	East System Load Center	West System Load Center	End-Use Hourly Load Shape
100 MW	12%	7%	Residential Cooling
100 MW	24%	24%	Commercial Cooling
100 MW	51%	51%	Commercial Lighting
100 MW	East load shape (approx. 65% load factor)	West load shape (approx. 67% load factor)	East or West System Load

<u>Step 9: Stress Case Analysis</u>

Stress case portfolios are devised and simulated to determine the impacts of base assumption changes or alternate supply options. An example would be a stress case to test the effect of an alternate planning margin. Many such stress case analyses are done in response to requests from the public concerning the base assumptions of the IRP. However, others are analyzed in response to requests from within PacifiCorp. Many insights can be gained from these simulations. It is expected that such insights will inform the Action Plan discussed in Chapter 9.

CONCLUSION

PacifiCorp's analytical approach to portfolio analysis is comprehensive, and results in the Preferred Portfolio of resource additions to meet future customer needs. The approach includes a detailed evaluation of portfolio alternatives and comprehensive risk analysis to determine the least-cost, risk informed portfolio.

6. RESOURCE ALTERNATIVES

OVERVIEW

There are a large number of options that could be used to fill the gap between PacifiCorp's known resources and anticipated load obligations. Prior PacifiCorp resource plans have discussed many of these options. This Integrated Resource Plan will focus on the candidate options that are known and are considered as realistic, feasible alternatives for balancing resource supply with electricity demand. Key resources that may be economical and could feasibly be developed by PacifiCorp to meet its needs include:

- Demand Side Management (DSM) programs – These resources are acquired through programs offered to the customer to reduce their energy usage.
- Distributed Generation – Refers to small- or medium-sized generating facilities located at or near loads. The dividing line between Distributed Generation and central station generation is not always clear. Distributed Generation generally includes Qualifying Facilities (QFs) and independently developed power projects located in conjunction with loads.
- Supply Side options – These resources are generating plants either owned by the utility or contracted by the utility. Examples of this type of resource include thermal generating units (coal and natural gas), hydroelectric generating units and renewable resources such as wind and geothermal.
- Market Purchases – These are purchase agreements with other parties that range from day ahead balancing transactions to purchases many years ahead. Established purchases used in portfolio building are considered as power purchase agreements (PPAs) which are dispatched on a least cost basis. Other term market purchases considered include: Call Option with fixed premium, Put Option with fixed premium, Swap, Tolling Option with fixed premium, Straight Block Purchases (e.g. 6x16, 7x24). The majority of PacifiCorp's market purchases are made 3 months to 5+ years ahead.
- Transmission Resources – As additional assets and access to markets become necessary to meet customer energy requirements, transmission network upgrades and additions are needed to meet this requirement most effectively.

In this chapter the characteristics of each resource type will be discussed. Following this discussion will be an assessment of how each resource was evaluated in the 2004 IRP.

DEMAND SIDE MANAGEMENT (DSM) RESOURCES

A number of influences can cause customers to use electricity more efficiently or to reduce energy temporarily during on-peak periods. These resources are categorized as DSM resources. A description of each DSM class was provided in Chapter 2.

Class 1 DSM Assessment

Existing Class 1 DSM programs are modeled as existing flexible resources. Potential new Class 1 DSM programs are modeled as potential "flexible units". The opportunities (types of programs and costs) evaluated are based on results from the DSM RFP 2003. (See Appendix C for a list of Class 1 DSM programs that were evaluated.)

Class 2 DSM Assessment

The load forecast in this IRP has been reduced by the amount of energy projected to be saved by existing programs, existing programs that are expanded to other states, and new cost effective programs that resulted from the DSM RFP 2003. These loads are shaped hourly based on the measures installed as projected for each program.

In addition, the load forecast has been reduced by the energy savings projection of the Energy Trust of Oregon. In Oregon, SB 1149 requires that investor-owned electric companies collect from all retail customers a public purpose charge equal to 3% of revenues collected from customers. Funds raised through this channel will be spent on energy conservation, new market transformation efforts, above-market costs of new renewable resources, and low-income weatherization. Of this amount 57% (1.7% of revenues) goes towards Class 2 DSM. The Energy Trust of Oregon (ETO) was set up to determine the manner in which public purpose funds will be spent. The Trust's legislative mandate expires in February 2012.

No new Class 2 programs beyond what has already been described are assumed in the resource plan. New programs will be obtained through RFP(s). The value of new Class 2 DSM opportunities has been developed through a decrement analysis on the Preferred Portfolio. These values determine the ceiling price under which the Preferred Portfolio can be modified through Class 2 DSM without increasing the PVRR of the Preferred Portfolio. A description of this process can be found in Chapter 5.

Class 3 DSM Assessment

Class 3 DSM programs are price responsive programs and tariffs that give customers a financial incentive to shift loads away from heavy load hours. They also conform to the IRP standards and guidelines to consider pricing in long-term planning. There has been no consistence or persistence in the load reductions observed through implementation of these programs at PacifiCorp.

At PacifiCorp, these price signals include: prices that vary the during the day (TOU) to encourage load shifting to off-peak hours; inverted block rates that raise prices for those that use large amounts of energy per month to encourage monthly energy reduction; interruptible tariffs for large customers to give customers value for flexible loads; day ahead price offers to "buy back" or reduce energy during specific high priced hours.

Currently, over 56% of PacifiCorp customers are eligible for some type of price responsive program or tariff. To date, there has been limited customer participation in these programs and negligible customer load shifting response to these pricing offers.

These types of programs are not included in this IRP as a long-term, reliable resource, however PacifiCorp will continue to investigate rate designs and price responsive programs that can reduce peak demand while still meeting simplicity, stability, and fairness criteria. These programs will be implemented tactically to reduce power costs as customers respond to price signals.

Class 4 DSM Assessment

Customer education programs are not included in the IRP as long-term, reliable resources. They will still be used tactically to try to improve customer conservation behavior over time.

DISTRIBUTED GENERATION

Purposes of Distributed Generation

Stand-By Power

The most common type of distributed generation provides emergency power in an outage. Customers with critical power needs such as hospitals, universities and large commercial office buildings have this capability. Several of these types of buildings are required by building codes to have stand-by generation. Such installations provide less power than is normally used by the facility. When grid power is available, however, stand-by generation could technically be fed into the grid if proper switching equipment were installed. Stand-by generation facilities are generally designed to minimize initial costs. Often, stand-by generation is provided by relatively small diesel engines that require low capital outlay but are expensive to operate.

"Premium Power" is a term applied to the continuous use of stand-by generation. This generation can improve both power quality and power reliability when backed up with grid-based power. This application requires a technology that can operate continuously. Customers considering this approach include banks, semiconductor manufacturers and hospitals.

Peak Shaving

Customers can use distributed generation to reduce their peak demand. Customers adopting this strategy are typically served by utilities with high demand charges. Customers may have low load factors and peak loads that occur at predictable times. Peak shaving facilities are sized to provide a desired amount of peak reduction and so are not sufficient to meet a facility's total load. Diesel generators or turbines that are relatively expensive to operate may provide peak shaving. Another possible example is installed Photovoltaic systems.

Continuous-Use Power

Some customers install generation in order to replace some or all of a utility's service to their 24-hour load requirements. Some customers may seek to completely avoid purchasing power from a utility when their own generation is available. Alternatively, customers may plan to have the utility regularly serve a portion of their facility's load. Because PacifiCorp's prices are relatively low, most continuous-use distributed generation is provided by cogeneration facilities. Customers may also continuously generate power using boilers that burn wood or other waste products.

Combined Heat and Power (CHP)

Customers install Combined Heat and Power (CHP), or cogeneration, to jointly produce electricity along with other forms of thermal or mechanical energy needed by their facility. Usually, cogeneration is installed in facilities that require substantial amounts of steam.

Cogeneration applications are often much lower in cost than other distributed generation technologies. Cogeneration can be energy efficient than stand-alone generation and makes joint use of key equipment. Depending on the customer's facility, cogeneration may require a larger boiler than would otherwise be required or customers may be able to install heat recovery equipment. Cogeneration typically, but not always, provides power on a continuous basis. The portion of a facility's electricity use provided by a cogeneration facility depends on the relation between the facility's steam needs and its power needs. In some circumstances, cogeneration may be capable of producing more than the facility's total electricity requirements.

System Reliability

Utilities may install distributed generation to improve system reliability in a local area. The dividing line between utility distributed generation and utility central generation is not distinct.

Technologies

Microturbines

Microturbines are small combustion-turbine generators that are developed on the basis of the turbocharger technology used in trucks and airplanes. The capacity range of microturbines (30 kilowatts to 400 kilowatts) covers the average load requirements (consumption needs) of most commercial and light industrial customers. Microturbines have relatively low emissions of pollutants, including nitrogen oxides, which would permit their installation in urban areas with restrictive emissions standards. Microturbine electricity generators are in the early stages of commercial development. A number of companies are currently field-testing demonstration units and several commercial units are available for purchase.

Fuel Cells

Fuel cells use an advanced electrochemical process to generate electricity. The process is comparable to that used in conventional batteries, except that the reactant material in fuel cells can be replenished so that the units will not run down. There are many types of fuel cells currently under development in the 5-1000+ kW size range. Technologies include phosphoric acid, proton exchange membrane, molten carbonate, solid oxide, alkaline, and direct methanol. Fuel cells produce virtually no emissions of air pollutants or greenhouse gases. Because their costs per installed kilowatt are high relative to those of conventional technologies, commercially available fuel cells currently suit only very specialized applications.

Photovoltaic Cells

Photovoltaic cells convert sunlight directly into electric current. Photovoltaic systems can be small, which is why they are used in residential settings, particularly in the Southwest and California. Photovoltaic cells produce no direct emissions and they have low maintenance requirements. Improvements in manufacturing processes have reduced the costs of photovoltaic systems significantly in the past decade. Even so, their acquisition and installation costs per kilowatt are still almost an order of magnitude greater than those of conventional systems and their costs per kilowatt-hour are three to four times the current average price of electricity in the United States.

Wind Turbines

Windmills have been used for many years to harness wind energy for mechanical work like pumping water. Before the 1920's, farms were using windmills to produce electricity. In the U.S. alone, eight million mechanical windmills have been installed. A mature technology, wind turbines are being widely used by utilities and independent power producers to generate energy. Large wind turbines are not generally considered to be a type of distributed generation because they are not usually located near customers. As with photovoltaic cells, the potential of wind generators is limited by available wind resources and by issues related to the siting of these large towers with their rotating wind blades (including noise and potential threats to migrating birds).

Small wind turbines designed for residential and rural applications now account for only a limited share of the market. For residential and small commercial distributed generation applications, suitable wind turbine capacities are 5 kilowatts to 50 kilowatts. The installed costs per kilowatt for those smaller systems are much higher than for the large systems. Even small wind generators require a large amount of space.

Business Arrangements

Manufacturers and Third Parties

Most distributed generation projects are developed in consultation with equipment manufacturers or third-party developers, perhaps with the assistance of consulting engineers and outside financing sources. According to a study commissioned by PacifiCorp, energy users believe that manufacturers and third-party developers are more credible equipment suppliers than utilities. One refinery customer in Utah stated, "Equipment manufacturers are obviously credible. That's their business. That's how they make their bread and butter. They'll try to outdo their competition." Another industrial customer said, "Third-party developers are not biased toward any particular equipment. They make their money by providing the best possible solution for us. We'd look for a company that has proven itself in the past."

Qualifying Facilities (QFs) and Independent Power Projects (IPPs)

Independent project developers may invest in distributed generation facilities. The distinction between QFs and IPPs is more a legal than a technical one. These types of facilities may use any type of generation technology, including hydroelectricity.

The Public Utilities Regulatory Policies Act (PURPA), a Federal statute, requires utilities to purchase the output from QFs at terms which are regulated by state commissions. The following types of facilities qualify under PURPA:

- Small power production facilities whose primary energy source is biomass, waste, renewable or geothermal. Generally such facilities must be less than 80 MW in size.
- Cogeneration facilities of any size. These facilities must meet operating and efficiency criteria set by FERC.

The prices and terms under which PacifiCorp purchases power from QFs vary from state to state. Generally, PacifiCorp purchases the output of smaller QFs at tariffed avoided cost prices. Because the characteristics of larger QFs are more variable, purchases are generally made under specific contracts, which are usually approved by state commissions and look to identify the exact costs that the QF allows the system to avoid. Negotiated contract terms generally follow established commission policies or practices.

QF policies have recently been under review in the states of Oregon and Utah. In Oregon, a commission proceeding is currently active. In this proceeding, PacifiCorp supports several changes that would favor QF development while not imposing undue costs on other customers.

The Utah Public Service Commission has recently approved a stipulation setting interim rules for QF purchases. The stipulation sets published prices for all QF purchases up to a cap of 275 MW. Customers may choose between two pricing regimes based upon the degree of control that PacifiCorp would have over their operations. Non-firm QFs receive a third pricing option related to the market.

Net Metering

Net metering is utility tariff service for customers with small generation equipment under which PacifiCorp bills the customer at retail prices for the difference between the electricity the customer consumes and the amount of generation the customer supplies to the grid. In effect, PacifiCorp purchases the output of the customer's generation at the retail price of electricity. Several of PacifiCorp's states require it to offer this service. PacifiCorp offers this service in all states, whether required or not. Net metering is also available for generation from renewable resources.

Customer Decision-Making

Customer Motivations

PacifiCorp commissioned the consulting group Primen to examine the factors important to customers regarding distributed generation. First, customers have some knowledge of distributed generation. Of a sample of 40 Utah commercial and industrial customers with loads between 10 kW and 10 MW, three-fourths were familiar with the basic applications of distributed generation. According to Primen, the number one driver for customers regarding distributed generation is a desire to reduce costs, either in the short- or long-term. Cost savings may occur in the form of reduced energy cost. Customers that install CHP see it as a way to get more control. Cost savings may also occur if CHP provides more reliable power. These cost savings would arise from reduced production losses associated with power quality events on the grid. Interestingly, Utah industrial customers in the study were less concerned about power quality issues than the national average because they experience fewer power quality events.

Customers have significant concerns regarding potential CHP installations. At the top of the list (from the Primen study) for Utah customers is concern about fuel prices. Customers are willing to consider price hedging mechanisms to lock in more predictable fuel prices. Customers are also concerned about service contracts and warranties available from their equipment suppliers. Further concerns include the financial health of their company, the state of the economy and their industry, and environmental issues.

The Importance of Timing

Distributed generation installations require significant capital expenditures, happen infrequently, and are highly dependent on market conditions at the time. The opportunity can occur when obsolete or failing equipment needs replacement, during plant expansion, or after a crisis of infrastructure such as a major energy event. The process of deciding whether to invest in distributed generation systems is not standardized among customers. Since the decision is infrequent, it tends to be made using an ad hoc process even within a given customer's organization.

Hurdles: Environmental and Infrastructure Requirements

Since numerous types of resources are categorized as distributed generation, each creates unique impacts on the environment. For instance wind facilities have visual and noise impacts which must be addressed although they don't emit pollutants. Stand-by generation is generally exempt from air quality regulation if used infrequently. In general, however, CHP installations must conform to air quality requirements. If located in a non-attainment area, air emission requirements can be stringent. CHP facilities must also procure sufficient fuel supply. If fueled by natural gas, a CHP facility must be able to obtain gas transportation to their local site. In addition, a CHP facility may be required to pay the costs of electricity transmission facilities needed to take its output into the grid.

CHP Activity in PacifiCorp's Service Area

As a result of the Primen study, PacifiCorp is working in conjunction with the Southwest Regional CHP Application Center to screen customers expressing an interest in CHP. Considerable QF activity is occurring in PacifiCorp's service area, particularly in Utah as a result of the revisions in QF rules described earlier in this chapter. There are approximately 190 MW of QF resources pending or approved in Utah. These include:

- Desert Power, a 90 MW facility that would come on line in January 2006;
- US Magnesium, a 36-49 MW facility that would come under a new contract in January 2005. The output of this facility will not be "scheduled" or "dispatched" by PacifiCorp;
- Tesoro, a facility that is providing 10 MW in excess of the host refinery's load which is now under contract. The output of this facility will not be "scheduled" or "dispatched" by PacifiCorp.
- Kennecott, a 32 MW facility which is also under contract. The output of this facility will not be "scheduled" or "dispatched" by PacifiCorp.

In addition, PacifiCorp has received notice letters from two very large projects. One would generate 2,000 MW in Wyoming and deliver the output to PacifiCorp's Utah service territory using transmission facilities to be built by the sponsor. The other would generate approximately 500 MW near Mona, Utah. Both projects would use natural gas as a fuel, one with methane. The projects claim to be able to deliver power by the summer of 2007. Neither of these "Jumbo" QF projects have identified a steam host or demonstrated that they meet the requirements of PURPA.

Cost and Risk Factors

Costs

Distributed generation facilities are highly site-specific and the costs can vary substantially. On average, most forms of distributed generation are more expensive than central generation alternatives.

Sources of Risk

Facility Risk

The output of a distributed generation project is linked to the operation of its host facility. In many cases, it would simply not be possible to operate CHP equipment if the associated facility were not in production. Since the overall economics of a customer's facility depends much more on the customer's business than on electricity, the output from a distributed generation facility is subject to an additional source of risk.

Financial Risk

A corollary to the issue of facility risk is the issue of financial risk should PacifiCorp invest in generation located on a customer's site or defer a planned resource through avoided cost pricing. Utility investment would be accompanied by a contract describing customer and utility obligations and containing credit provisions. Once installed, CHP equipment becomes an integral part of the customer's facility. It is difficult to design contract terms that do not jeopardize a key part of a customer's facility and that provide adequate surety of the utility's investment. The result can easily be greater risk for ratepayers. CHP customers have generally preferred to finance the installation of generating equipment using other sources.

System Planning Uncertainties

Because customers, not PacifiCorp, control the timing and location of distributed generation, the result may substantially increase planning uncertainty and risk. For example, PacifiCorp makes planning assumptions based on contractual commitments from QF projects. If those projects fail to meet their contractual on-line dates, PacifiCorp's ability to meet resource needs may be adversely impacted.

As discussed earlier, hundreds, perhaps thousands, of megawatts of QFs may come on line in the near future. Such QFs may obtain avoided cost pricing based on avoiding a resource.

If identified QF projects actually begin deliveries in the near future, PacifiCorp may be forced to reduce output from less expensive Company-owned generation, paying the QFs the marginal cost of this avoided generation, and construct additional transmission reinforcements. The IRP assumes that the four pending QF projects in Utah will come on line as expected. The IRP does not reflect the two "Jumbo" projects that are less far advanced and may only qualify for avoided fuel costs for a large portion of their output.

Distributed Generation Assessment

Distributed generation options with acceptable costs were modeled as a set of stress case runs. The two options modeled include CHP and customer-owned standby generators.

Combined Heat and Power

The Northwest Power and Conservation Council (NPCC) in its draft Fifth plan stated that "because of its generally small-scale, diversity, and unpredictable schedule, the Council did not evaluate cogeneration in the portfolio analysis”.[10] Although PacifiCorp agrees with this conclusion, some effort is made in this IRP to account for the effect of CHP coming in as a distributed resource over the Action Plan timeframe.

In the eastern system, particularly the Wasatch Front in Utah, 190 MW of CHP is being modeled in the 2004 IRP.[11] In the western system, a stress run was made to the Preferred Portfolio to determine the effect of 90 MW of CHP displacing the first supply-side unit needed. (See Chapter 8 for simulation results and Appendix E for the scorecard.)

Standby Generators
A stress case was run in the eastern and western systems to test the effect of displacing the first supply-side unit in each area. See Chapter 8 and Appendix E for stress case results.

SUPPLY SIDE RESOURCES

For the purpose of modeling portfolios, PacifiCorp has identified a list of prospective resources for balancing resource supply with electricity demand based on options uniquely available to PacifiCorp. Tables C.27 and C.28 in Appendix C list these resources and their specific operating characteristics.

Pulverized Coal
Coal is burned in approximately 55% of power plants nationwide and is used to generate 45% of the electricity needs in the United States. Coal plants are generally considered “continuous-use” units and are relatively inexpensive to operate primarily due to historically low fuel costs when compared to natural gas units. ”Continuous-use” coal plants are operated to supply all or the majority of the minimum continuous load of a system and produce electricity at an essentially constant rate. Traditional large coal units use pulverized coal boilers and control emissions through a combination of in-furnace technology (Low-NO_X Burners) and post combustion controls such as Fabric Filters, Selective Catalytic Reduction for NO_X removal and flue gas desulfurization (FGD). New pulverized coal units are capable of high levels of emission control with 95% or better SO_2 removal, over 90% NO_X removal compared to older designs, and 99.99% or greater particulate removal. In addition to air pollution concerns, coal plants require a significant and consistent water supply for cooling purposes and they produce waste products and heat which all have environmental impacts. Visual aesthetics and impacts of mining, transporting, and storing coal are also considered in the permitting and siting of a new plant.

There are two types of boilers associated with pulverized coal units: subcritical and supercritical. Subcritical pulverized coal boilers generally use natural or forced circulation systems to produce steam in a steam drum. Large PC plants generally operate the steam drum at a maximum pressure of 2400 psi. Supercritical pulverized coal boilers produce steam in the waterwall tubes without the use of a steam drum. Pressures in a supercritical boiler are generally in the 3600 psi

[10] Fifth Pacific Northwest Electric Power and Conservation Plan (draft), Northwest Power Planning and Conservation Council, September 24, 2004
[11] 90 MW is considered an Existing Resource and 100 MW as a Planned Resource.

range and are only of the natural circulation design. The higher pressure steam can then be used in a steam turbine resulting in higher cycle efficiencies. The heavier high pressure design for the supercritical boiler results in a more expensive boiler the higher cost of which can be offset by the higher efficiency of the cycle depending on the fuel cost.

Integrated Gasification Combined Cycle (IGCC)

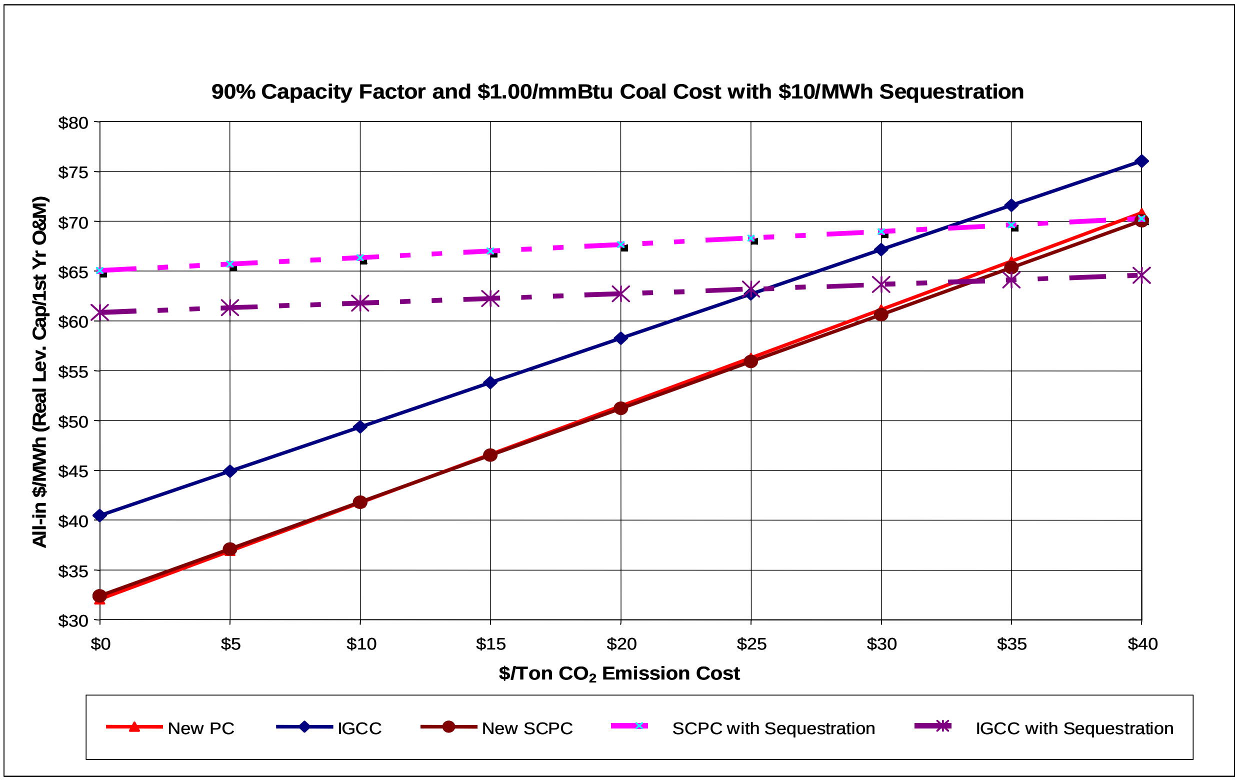
Integrated Gasification Combined Cycle (IGCC) is a clean coal technology that utilizes a coal gasification process to produce clean fuel that can then be used to fuel a combined cycle gas turbine. This technology can achieve slightly lower pollutant emission levels and higher efficiencies than a conventional pulverized coal-fired plant. IGCC is only now beginning to reach full commercialization. There are a half a dozen or so commercial plants in the world to date and most of these are fueled by petroleum residuals. Capacity factors for these plants typically have been less than 80%. Work is being done to improve their operation on both coal and petroleum residuals and progress in this area is expected. Capital and operating costs are higher than those of traditional coal-fired plants, but these could come down as larger economies of scale are reached. IGCC production costs in the Utah and Wyoming areas will be further disadvantaged compared to most areas of the United States because of elevation de-rating of the turbines. The next generation of IGCC plants will likely be designed around bituminous fuels, therefore Powder River Basin (PRB) coals may not currently be the best fuel candidates for IGCC plants in the next few years. In the 2004 IRP it was assumed that an “H” combined cycle IGCC unit without a spare gasifier would be the most likely IGCC resource with an expected installation date of FY 2015. This resource is further defined in Appendix C.

Based on recent discussions with technology suppliers, assumptions concerning the short-term characteristics of IGCC resources are changing. These changing assumptions were developed only recently after the modeling evaluation process of this IRP and should be considered as very preliminary. The new assumptions from the technology suppliers concerning the IGCC resource use a “7FB” based gas turbine combined cycle in a 3x2x1 configuration (3 gasifiers, 2 gas turbines, 1 steam turbine) and have an expected availability of 90%. The expected availability of the “H” unit without a spare gasifier was 75%. Off-setting this improvement in availability with the “7FB” machine is a higher heat rate and capital costs that are not as favorable. Based on recent information, emissions from this configuration appear to be better than for the “H” machine assumptions. It is assumed that up to 90% of the CO_2 emissions can be captured with a water gas shift reaction and amine scrubbing. After capturing the carbon, the carbon would have to be sequestered and the most recent information suggests that the cost of carbon sequestration would be around $10 per MWh. Based on EPRI and GE data it would be less costly to add carbon capture on IGCC units than on pulverized coal units. Figure 6.1 compares the “all-in” cost of the IGCC and the pulverized coal unit with and without carbon collection and carbon dioxide sequestration at differing levels of CO_2 emission costs.

The environmental impacts to be considered from an IGCC plant are similar to those of a pulverized coal plant although IGCC would produce fewer SO_2, NO_X, and Hg emissions. With the addition of carbon capture and sequestration, 90% of CO_2 emissions would be eliminated. Beside air emissions, environmental impacts on surface and ground water, land use, visual aesthetics, waste disposal, and fuel mining, transport, and storage all have to be considered in the permitting and evaluation process.

Figure 6.1 illustrates that IGCC has relatively high costs compared with the new pulverized coal (PC) units and the new supercritical pulverized coal units (SCPC) but there are still benefits to this resource type, e.g., incrementally lower emissions and an easier transition to carbon capture and sequestration. Further, the graph illustrates that at a CO_2 allowance cost of approximately \$33 per ton, IGCC with carbon capture and sequestration would "break-even" with the cost of pulverized coal without carbon capture and sequestration.

Figure 6.1 IGCC Cost Comparison



Coal Portfolio Assessment

Pulverized Coal

In the eastern control area subcritical and supercritical pulverized coal units and IGCC units were considered for this IRP. Generally supercritical pulverized units have better heat rates than subcritical units but are more costly in terms of capital and O&M. Primarily the sites of the plants considered were in central Utah near the existing Hunter plant and near the existing Bridger plant in Wyoming.

A subcritical unit having a capacity of 575 MW at the existing Hunter plant (Hunter 4) in central Utah was evaluated during the modeling process with various installation dates. This Hunter unit would use the latest available emission control technology for SO_2, NO_X, and particulates. The Hunter site is presently viewed as an excellent company owned location for an additional unit because the existing units already there would lend supporting infrastructure (substation and transmission included) and manpower to its operation.

A pulverized coal unit in Wyoming was considered and evaluated during the modeling process in Wyoming. A fifth unit at the Jim Bridger Plant represents the first plant in excess of 500 MW in Wyoming. For these portfolios, PacifiCorp assumed a two-thirds ownership share of both plant and transmission, consistent with the current Bridger plant ownership agreement with Idaho Power Company. Capital costs for this unit was derived from the design and cost for Hunter 4, a plant of similar size with allowances for burning Powder River Basin (PRB) coal. Two units were also evaluated at the Jim Bridger site as another portfolio. Both units were assumed to have maximum capacity of 575 MW but it was assumed that PacifiCorp would have two-thirds ownership of one of the units. For these portfolios with coal units at the Jim Bridger location transmission expansions were necessary in the Jim Bridger to Wyoming path and the Wyoming to Utah North path.

IGCC

A 368 MW IGCC unit using an advanced "H" type combustion turbine was considered and evaluated during the modeling process. This technology was assumed to be available during FY 2015. This technology could either be located in Utah or Wyoming and would use either bituminous or PRB type coal.

For one of the stress case portfolios evaluated, PacifiCorp assumed the procurement of a "7FB" IGCC unit in FY 2011 with the new technology characteristics (See Chapter 7 for a description of this IGCC portfolio). Investigation of IGCC with updated technology and commercialization attributes will continue in subsequent Action Plan analyses and IRP filings. Based on these promising, although very preliminary, assumptions and results, PacifiCorp will continue to investigate this potential resource as the next coal unit.

NATURAL GAS

Combined-Cycle Combustion Turbines

The Combined-Cycle Combustion Turbine (CCCT) is a gas turbine technology with additional electricity produced from otherwise lost waste heat. The exiting heat is routed to a heat recovery steam generator to produce steam for use by a steam turbine to generate electricity. As a result the efficiency of the plant is increased.

A 2x1 configuration (two gas turbines and one steam turbine) is the best representation for a CCCT with an expected capacity factor of between 15% and 100%. Other combined cycle configurations are possible including a 1x1 design (one gas turbine and one steam turbine). The 1x1 design is easier to start and stop on a frequent basis and has a quicker starting time profile. However, these advantages do not overcome the 2x1 configuration's advantage in capital cost and efficiency.

Combined cycle equipment is considered with the option of adding duct firing for additional flexible capacity. This option may or may not be available with all CCCT suppliers but has been included to reflect the capability of the machines represented in the analysis. Duct firing will require additional investment in gas burners and the steam turbine system.

Simple-Cycle Combustion Turbines (SCCTs)

Three types of SCCTs were considered in the planning process: aeroderivative (aero) machines, frame machines, and the intercooled aeroderivative machine.

The aero machines are flexible units as represented by the LM6000 design located at Gadsby. These machines have high efficiency and can start within 10 minutes to qualify as operating reserves.

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

Intercooled aeroderivative simple cycle combustion turbines (IC Aero SCCT) are also considered. This new gas turbine design will have better heat rates than the other two. The capital cost of this machine is comparable to the combined cycle machines but is less than the conventional aero machines. These machines generally will take less time to construct than combined-cycle units. Also, these machines can meet lower emission limits than the other types of SCCTs. Since these machines are still new in the market place there is a slightly higher degree of technical risk than other SCCT options based on proven technologies.

Internal Combustion Engines

Internal combustion engines were considered as a flexible resource in the IRP process. These engines are large (~11MW) stationary diesel machines which operate on natural gas. These engines have good emission profiles and can be built with relatively short lead times. The NO_X emissions rate is higher than the intercooled and conventional SCCT aero machine. Capital and operating costs will be competitive with frame SCCTs with a better efficiency but creating large blocks of power is somewhat restrictive due to the large number of machines required and the higher emissions level.

Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) was considered as an energy resource during the current IRP process. Using CAES, off-peak power is used to pump air into a sealed underground mine or cavern to a high pressure. This pressurized air is stored in the mine or cavern for later use during peak hours. The compressed-air energy from the cavern is supplemented with natural gas fuel to generate electricity during peak hours. A CAES plant has fast start-up times. This type of plant can provide a start-up time of approximately nine minutes in an emergency, or twelve minutes under normal operating conditions. The CAES system can also be used to store energy for more than a year. The main disadvantage of these plants is the limited availability and cost of underground storage caverns which limits this as a viable option.

Gas Portfolio Assessment

For both the east and west the 2x1 CCCT configuration was considered and evaluated in the modeling process. With this configuration both wet and dry cooled machines were considered. The wet cooled machine is expected to be more efficient than the dry cooled machine. For each case a duct firing unit was assumed to be utilized.

The 1x1 CCCT F-machine was not included in the modeling evaluation process. Although this technology has a favorable heat rate, the construction and fixed O & M costs on a per kW basis is higher than that for the CCCT with duct firing.

The intercooled aero SCCT was the only flexible SCCT resource evaluated in the IRP modeling process. The intercooled machines are more efficient, less costly and have a lower NO_X emissions rating than the other types of SCCT machines.

Due to higher overall costs and higher NO_X emissions rates the internal combustion engines were not considered in the modeling evaluation process.

The CAES was considered in modeling evaluation as a flexible resource since it is considered to have reduced emissions and has potentially lower operating costs.

RENEWABLE RESOURCES

Wind

Using wind energy requires careful consideration and knowledge of the specific wind source in order to assess the performance of a resource at a given site. Wind energy has only minor impacts on the environment and produces no air pollutants or greenhouse gases. Wind energy is therefore considered a green power technology. While historically the cost for wind energy has been high, continued research and development efforts are helping to reduce costs. Incentives like the federal production tax credit have also helped improve the economics of wind energy. Capacity factors for these plants typically range between 30% and 40%. The capacity contribution of this resource for meeting summer system peak demand is estimated to be 20%.

Biomass

Biomass generation is a generation unit that uses any organic matter as a fuel to generate energy. Wood and wood waste are common examples of biomass fuel. Biomass also includes such items as agricultural waste, lawn and yard waste, and animal waste. All of these organic matters can be converted into energy producing fuels.

Geothermal

In geothermal power plants steam, heat or hot water from geothermal reservoirs provides the force that spins the turbine generators and produces electricity. The used geothermal water is then returned down an injection well into the reservoir to be reheated, to maintain pressure, and to sustain the reservoir. Geothermal plants are considered a renewable resource as they have a clean emissions profile and utilize a renewable resource. Depending on how the geothermal reservoir is developed, operating costs can be competitive. PacifiCorp currently operates the Blundell plant as a geothermal resource. Steam cost prohibits this resource from being one of PacifiCorp's lower cost resources and has slowed subsequent development of additional units at the Blundell Plant.

Renewable Portfolio Assessment
For modeling evaluation purposes 1,400 MW of wind capacity was modeled as a Planned Resource. The 1,400 MW was determined in accordance with the 2003 IRP and renewable RFP process, including the ongoing RFP 2003-B. Further discussion of this issue is in Chapter 3 and Appendix J.

HYDROELECTRIC GENERATION RESOURCES

Hydro
Hydroelectric generation is America's leading renewable energy resource. A hydroelectric generating unit uses water from a river, lake, or reservoir held behind a dam, that when operating, allows the force of the water to pass through the dam and turn the turbines of the generating unit. In traditional hydroelectric generation, water is typically stored in the lake or reservoir behind the dam until it is released through the dam. Although hydroelectric generation produces no polluting air emissions, it can have significant environmental impacts on surrounding land use and aquatic habitat. All these environmental impacts are addressed within the licensing process.

Pumped Storage
This type of plant usually generates electric energy during periods of high demand by using water previously pumped into an elevated storage reservoir during periods of low demand when excess generating capacity is available. When the additional capacity is needed, water can be released from the reservoir to turbine generators located at a lower level.

Hydro Portfolio Assessment
A pumped hydroelectric storage resource was considered for modeling evaluation purposes on the east side of the system due to its potential for being a flexible generation unit and its potential as a low cost flexible resource.

OTHER GENERATION RESOURCES

The generation resources in this section are not found in the supply side options table in Appendix C and were not modeled in this IRP. The reasons for not modeling these options will be discussed below.

Circulating Fluidized Bed (CFB)
Circulating Fluidized Bed (CFB) boilers are an alternative to pulverized coal boilers for the combustion of solid fuels such as coal or petroleum coke (pet coke). CFB boilers combust ground coal in a bed of coal and sand. Combustion air is bubbled vertically into the furnace and the combustion air suspends the coal mixture. The addition of heat to the "fluidized bed"

generates sufficient energy to boil water in the furnace creating steam in conventional steam drums. CFB boilers have an advantage in burning low quality fuels such as waste coals left over from coal cleaning processes. CFB boilers have inherently lower emissions of SO_2 and NO_X. SO_2 is removed by adding limestone into the furnace and NO_X formation is constrained because of lower combustion temperatures. Still, SO_2 and NO_X levels are not low enough with just the furnace based reductions and new CFB boilers also use additional SO_2 post-combustion control and NO_X post combustion SCR controls. Because of the lower levels of emissions leaving the furnace these post-combustion controls can be smaller in size, use less reagent, and produce less emission waste than comparable post-combustion controls on conventional pulverized coal boilers.

Circulating Fluidized Bed Assessment
The CFB was not modeled for several reasons. The option is considered to be equivalent to a subcritical boiler for resource evaluation purposes. A CFB can accommodate a wider variety of coal and can burn some waste coal not usable in a more standard boiler. The overall efficiency of the CFB will be very close to a subcritical design. For PacifiCorp's application using high quality Utah fuels or readily available sub-bituminous Wyoming fuels causes the use of a CFB boiler unnecessary. Also, the environmental footprint of the CFB is very similar to the subcritical or supercritical design. The total cost of a CFB is slightly more than a comparable supercritical design especially for larger systems. Overall capital cost is slightly higher and boiler efficiency equal to similarly sized pulverized coal plants. One distinct disadvantage of a CFB boiler is a limitation on size. CFB boilers have been built up to 300 MWs in size compared to conventional pulverized coal boilers which have been built up to 1,200 MW. When larger capacities are needed multiple boilers have been built causing more cost. For a Hunter 4 size coal plant, two CFB boilers would be needed feeding steam to a single steam turbine. The balance of a CFB facility would be identical to a pulverized coal facility and would consist of a steam turbine and associated cooling tower.

<u>Dual Fuel IGCC</u>
Dual-fuel IGCC refers to an electrical generating plant capable of operating on either coal (or other solid fuel) or natural gas. Since an IGCC plant uses a combined cycle gas turbine the facility can use coal derived syngas or natural gas to fire the combustion turbine. The ability to use natural gas helps to increase plant availability by allowing the plant to operate when the gasifiers are unavailable.

Dual Fuel IGCC Assessment
Dual fuel IGCC was not modeled because the "H" design considered and modeled in the 2004 IRP would already have the capability of using natural gas as an alternative fuel. The assumed 75% availability rate of the "H" design IGCC unit does not assume the inclusion of a spare gasifier which would operate at the other times. During the Public Input Meeting of November 10, 2004 PacifiCorp committed to continue investigating a new IGCC technology, the "7FB" design. Part of that investigation will be the consideration of a spare gasifier on the unit. The operation of the spare gasifier is considered to be more economic than using natural gas as a secondary fuel.

Nuclear Power

Nuclear generated power started in the 1950s and the amount of power generated by nuclear units has been on an increasing trend since that time. Since 1984 nuclear generation has the second largest share of generation in the nation. Despite the strong share of nuclear generation, no new nuclear units have been ordered since 1978. The last nuclear unit to go into service in the U.S. was in 1997.

Operations and start-up for nuclear turbines and generators are similar to other types of steam turbines. Nuclear turbines are steam turbines with power supplied by fission instead of coal or natural gas. Steam in a nuclear unit is generated by heat produced by the radioactive reaction of uranium fuel. This reaction is controlled through the raising or lowering of graphite control rods which controls the amount of heat generated in the unit.

Nuclear Power Assessment

There are advantages and disadvantages to considering nuclear power as a resource option. Nuclear power is carbon free and is considered a reliable source of continuous-use energy. Newer nuclear technologies appear to be cleaner and safer than the earlier generations of this technology. This source of generation has a significant technical potential as part of a balanced portfolio that would reduce the need for energy imports. PacifiCorp's view is that only after the thorough consideration and use of renewable resources, DSM and other energy reduction programs, high efficient gas resources, clean coal resources, and hydroelectric resources would nuclear generation be considered. In summary, nuclear generation was not considered for the following reasons:

- Siting and environmental concerns
- Lack of public acceptance
- High initial capital costs compounded by a long lead time
- Long term liabilities associated with waste and decommissioning

MARKET PURCHASES/CONTRACTS

The process of developing portfolios must also contemplate supplemental access to the spot market. PacifiCorp considered several methods for representing market purchases and sales. The following resources are representative of the 1,200 MW Front Office Transactions discussed in Chapter 3. These resources are also representative of all other market purchase and sales contracts.

Asset-Based, Long Term Power Purchase Agreements (PPA)

These purchases are from energy merchants and other industrials offering surplus electricity that they have available. Contracts may have fixed prices and are likely to be used in the heavy demand hours; or the price of contracts may be tied to market indices and would dispatch based on least cost as compared to their associated markets.

Shaped Products

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

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

- **Call Option with fixed premium –** The option buyer has the right but not the obligation to call, or rather, buy energy and capacity at a defined strike price in exchange for a premium. The buyer would likely exercise this option when market prices exceed the strike price.
- **Put Option with fixed premium –** The option buyer has the right but not the obligation to put, or rather, sell energy and capacity at a defined strike price in exchange for a premium. The buyer would likely exercise this option when market prices are below the strike price.
- **Swap –** A swap is an agreement whereby a floating price is exchanged for a fixed price, thus resulting in an exchange of cash flows between a swap seller and the swap buyer. This product typically involves no transfer of physical energy or capacity, but is nevertheless a common and practical way of financially hedging physical risks. The seller of a swap is naturally long energy and capacity, and is looking to hedge exposure to decreasing prices. The buyer of a swap is naturally short energy and capacity, and is looking to hedge exposure to increasing prices. If prices move up, versus the fixed price, the seller pays the buyer the difference between the index and the fixed strike, thus keeping both parties neutral to the agreed upon fixed price. If prices move down, versus the fixed price, the buyer pays the seller the difference between the fixed strike and the index, thus keeping both parties neutral to the agreed upon fixed price.
- **Tolling Option with premium -** The option buyer has the right but not the obligation to call, or rather, buy energy and capacity at a potentially defined heat rate multiplied by a gas price index (energy price) in exchange for a fixed premium. The buyer would likely exercise this option when market price for electricity exceeds this energy price. This option might be used instead of a call option with a fixed strike price. This type of structure may also be formed as a physical tolling option where the buyer provides the fuel and the seller provides the service of converting the fuel into electricity.
- **Straight Block Purchases (e.g. 6 x 16, 7 x 24) –** Buyer has the obligation to take and pay for energy and capacity at specific rates at a fixed price. This product involves the transfer of physical energy and capacity. A buyer of a straight block purchase is short energy and capacity, and thus purchases this product to alleviate exposure to price movement. The buyer reduces his floating price exposure and receives energy and capacity at a fixed price. The seller reduces his index price exposure and sells energy and capacity at a fixed price. This product is the physical equivalent to the aforementioned swap.

Market Purchase Portfolio Assessment

In the IRP portfolio building process a maximum of 1,200 MW of Front Office Transactions are included as a Planned Resource. These Front Office transactions are a mixture of term contracts ranging to more than 5 years duration. A more detailed discussion of these transactions is provided in Chapter 3 and Appendix C.

TRANSMISSION

Eastern Control Area

The Wasatch Front (WF) load center relies on generation that is distant from the load center. As electricity is imported from the outside the load center, the high-voltage transmission lines and step-down transformers become heavily loaded. With these large imports, reactive power is required at the load center in order to maintain proper voltage. Some of this reactive power can be supplied by switched capacitors up to a certain point. Beyond that point, large dynamic reactive devices, i.e. Static-Var Compensators, are required. Costs for such devices have been included in the IRP portfolios.

In addition to the reactive power needs, additional high-voltage lines and transformers are needed to provide sufficient capacity in delivering the power to the loads at the delivery voltage. Hence costs are included in the IRP portfolios for these facilities. The farther the new resources are located from the load center, the longer the required transmission lines will be. For very long transmission lines and where there are limited corridors, higher voltages are considered as a more practical solution.

Resources included within the WF, especially in the Salt Lake valley, may have much lower transmission costs because of shorter distances to the loads at lower delivery voltage levels.

As imported electricity into the WF from the south increases, physical limitations are reached in the number of power line corridors that can be used. The number of line terminations at any one substation is also limited. For this reason, costs are included in some portfolios for completely new substations (Oquirrh) and new line corridors (Mona to Oquirrh). In the case of new resources at Four Corners, 500 KV facilities are included because of the distance from the load center and because of limited corridor space.

The transmission path from Wyoming to Utah is fully utilized. Any new resources in Wyoming (i.e. Naughton or Bridger) will require new long, high-voltage transmission lines in new corridors. These costs are included in the IRP portfolios (i.e. Bridger to Naughton to Ben Lomond).

Western Control Area

The PacifiCorp west control area is constrained by the Bridger generation and transmission rights across Idaho. Any additional generation to bring new resources into the PacifiCorp system from Idaho will require expansion of the transmission system, such as a second Midpoint-Summer Lake 500 kV line.

Additional resources, such as wind, added in the vicinity of Walla Walla, will require the construction of new transmission as the existing transmission is fully utilized. Moving electrical power to Mid-Columbia or the Yakima area requires construction of a new 230 kV transmission line from Walla Walla to Outlook. To move generation to other load areas of the PacifiCorp western system requires construction of a new 230 kV line from Walla Walla to McNary. However, this only gets to the edge of PacifiCorp's system, and thus requires additional wheeling from BPA to get to other load areas. The west of McNary path (BPA transmission) is fully utilized and BPA has a current solicitation for expansion of this path (McNary-John Day Expansion Project).

Moving generation northward from southern Oregon is limited by the capacity of the Alvey-Fry 230 kV line. This line is fully utilized for network load service. Additional generation to move resources northward to the Albany area requires construction of a new 230 kV line from Alvey to Fry.

Moving generation from the Albany area to the Portland area is limited by agreements with third parties. This third party capacity is fully utilized for network load service and would require additional wheeling on third party systems or the construction of a new 230 kV line between Bethel and Gresham.

Transmission Portfolio Assessment

For each portfolio transmission upgrades and additions are implemented as necessary with the appropriate costs included in the analyses. The transmission resources included in the IRP portfolios are based on high-level designs stemming from previous PacifiCorp analyses and experience, rather than detailed power flow studies. The capital costs are derived from past construction costs, and are intended as approximate values for portfolio comparisons only. These estimates include costs for construction of new substations, new transmission lines, and new voltage control equipment (i.e. capacitors and Static Var Compensators). The costs also include the expansion of existing substations for new line terminations, switches, additional transformer capacity and voltage equipment. These costs are for delivering the power from the generating site to the load center. They do not include any costs for interconnection of the new generation resources. Such interconnection costs are included in the capital costs for the supply-side resources.

7. RESOURCE PORTFOLIOS

INTRODUCTION

This chapter describes the portfolios that were developed and evaluated based on the methodology described in Chapter 5. Each portfolio contains realistic, feasible supply side alternatives for balancing resource supply with electricity demand.

The portfolio inventory consists of two general types: *Candidate Portfolios* and *Stress Case Portfolios*. A Candidate Portfolio represents a contender for risk analysis and subsequent selection as the preferred supply side portfolio and ultimately the Preferred Portfolio (the preferred supply side portfolio with Class 1 DSM incorporated into the resource mix). Candidate portfolios were developed by altering the type, timing, and size of supply side resource alternatives, and comparing the simulation results to arrive at top PVRR performers. A stress case portfolio is intended to inform the study of certain alternative portfolio design assumptions, with the objective of informing the Action Plan and its implementation as described in Chapter 9. Specific design assumptions include the Planning Margin level, replacing Front Office Transactions with build-or-buy assets, substituting flexible resource assets with Distributed Generation alternatives, and assuming early IGCC commercial viability. Stress case portfolios are not in the running for selection as the 2004 IRP Preferred Portfolio.

The chapter begins by describing the concept of the proxy resource, and then briefly summarizes the resource timing requirement that portfolios are designed to address. Next, the portfolio categorization scheme used to group portfolios is discussed. Finally, the portfolios, organized by category, are presented in the form of resource tables that show additions by location (east or west), resource type, size (in Megawatts), region, and in-service year. The design objectives for each portfolio are also described. Note that portfolio tables listing capital costs for each resource are provided in Appendix D.

PORTFOLIO DEVELOPMENT

Several candidate portfolios were developed which can meet future resource requirements. All of these portfolios required substantial resource additions to meet peak demand growth of 3.8% in the east and 1.5% in the west per year, to replace resources that are lost through attrition of the existing base of resources, and to cover the 15% planning margin. These resource additions were added to the resource base data, which are comprised of Existing Resources and Planned Resources (See Chapter 3 for more details).

Proxy Resources

Portfolios presented in this chapter use various resources to fill the resource need in the IRP planning horizon. It is important to understand that the resources used for this purpose are considered proxy resources. A proxy resource is defined as a resource that has estimated cost and operating characteristics that can address PacifiCorp's expected short position. It is a surrogate for either a build or purchase option. The actual decision to build or buy a particular resource is made during the procurement process.

Timing of Resource Additions

The load and resource balance described in Chapter 3 revealed a resource deficit that requires the addition of large resource blocks in various years of the planning horizon. As indicated in Table 7.1, total system resource additions of approximately 2,800 MW are required in the next ten years (see Chapter 3 and Appendix F for more detailed load and resource balance information).

Table 7.1 – Annual Resource Deficits

Fiscal Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Obligation x PM	11,485	11,701	11,988	11,639	11,916	12,177	12,478	12,650	13,035	13,434
Existing Resources	11,064	11,004	11,163	10,226	10,146	10,126	9,977	9,317	9,315	9,077
Planned Resources	420	710	850	1,340	1,380	1,420	1,560	1,580	1,580	1,580
Deficit	(1)	13	25	(73)	(390)	(631)	(941)	(1,753)	(2,140)	(2,777)

Additions are required on both the eastern and western sides of PacifiCorp's system. The eastern side of the PacifiCorp system requires large resource additions in FY 2009, FY 2011, FY 2014 and FY 2015. The western side of the PacifiCorp system requires a large addition in FY 2013. This pattern of resource addition requirements was the basis for the development of the portfolios discussed in this chapter.

Portfolio Categories

There were numerous portfolios developed to be candidates for the Preferred Portfolio. To explore a broad range of possible resource mixes, candidate portfolios were developed according to the following seven categories:

1. Reference Portfolio
2. Fuel Type Change
3. Technology Change
4. Sequencing of Plants
5. Location Change
6. Storage Technologies
7. Capacity Expansion Model (CEM)

CANDIDATE PORTFOLIOS

The following section discusses each category and the various candidate portfolios in detail. The portfolio names are always preceded with a letter which reflects the chronological order in which the portfolios were developed. All portfolio tables use fiscal years.

Portfolio Category: Reference Portfolio

This category is comprised of one portfolio which is the Reference Portfolio. It serves as the benchmark for the development and evaluation of other portfolios.

The Reference Portfolio was developed based on the experience of PacifiCorp personnel and is the starting point for the IRP portfolio development process (see Chapter 5). Other portfolios presented in this chapter generally reflect one-element variations of this Reference Portfolio.

Depicted in Table 7.2, the Reference Portfolio contains a mix of new gas and coal resources reflecting a fuel-type diversification tactic for modeling new capacity additions. A diversified portfolio is defined as having a mix of new resource types that helps to balance the current system resource mix. PacifiCorp's current resource mix is dominated by coal at 78% of total nameplate capacity. The Reference Portfolio (A) has a coal-to-gas mix of 34% to 66%.

Gas resources are included in the east in FY 2009 and FY 2014, and in the west in FY 2013. Coal resources are included in the east in FY 2011 and FY 2015. Since there have been recent advancements in clean coal technology, for portfolio concept testing purposes PacifiCorp assumed that Integrated Gasification Combined Cycle (IGCC) represents a viable resource technology for an out-year baseload resource requirement. Consequently, a resource needed in FY 2015 was specified as an IGCC plant.[12]

Table 7.2 – Portfolio A: Reference

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S						575					575
	Greenfield IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N									560		560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Portfolio Category: Fuel Type Change

The purpose of this category is to study the effects of adding resources with different fuel types to the Reference Portfolio (i.e., gas versus coal-fired resources). Three portfolios were constructed to test these effects.

The portfolio shown in Table 7.3 reflects replacement of the Utah brownfield coal plant in FY 2011 with a Utah dry cooled CCCT plant. Thus, the IGCC plant in FY 2015 is the only new coal resource in this portfolio. There are two primary cost impacts that were targeted for study through testing this portfolio. First, that increasing the percentage of gas in the portfolio should increase the resulting emissions cost credit due to the lower emissions rates of the CCCT technology (however, this could be offset by the lower capacity factors expected for CCCTs relative to pulverized coal). Second, that the lower capital costs of the CCCT will be an advantage over the Utah coal plant.

[12] The IGCC resource does not reflect carbon capture/sequestration capabilities and associated costs.

Table 7.3 – Portfolio B: Remove Utah PC, Replace with Gas

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Greenfield IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525		525					1050
	Wet Cool CCCT w/ DF	Utah-N									560		560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

The objective of the portfolio shown in Table 7.4 was to test the hypothesis that replacing all of the coal resources with gas resources would result in a low PVRR. Thus, the Utah brownfield coal plant was replaced with a Utah dry cool CCCT plant, and the Wyoming IGCC was replaced with a Utah wet cool CCCT. A cost advantage of replacing coal with CCCT gas resources would be realized from CCCTs' significantly smaller capital costs, superior operating flexibility, and greater emissions cost credits relative to comparably-sized coal resources. The question is whether these cost advantages with respect to coal outweigh CCCTs' much greater variable costs (particularly fuel and spot market purchase costs). An additional purpose for developing this portfolio was to analyze, via Stochastic and Scenario risk analysis, a portfolio with high risk exposure to fuel and power markets.

Table 7.4 – Portfolio M: All Gas with CCCTs

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Dry Cool CCCT w/ DF	Utah-S				525		525					1050
	Wet Cool CCCT w/ DF	Utah-N									560	560	1120
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								194			194

Derived from portfolio E (discussed on the next page), the portfolio in Table 7.5 replaces a wet cool CCCT unit with a second Wyoming pulverized coal plant. One of these coal plants and the transmission upgrade was assumed to be at two-thirds ownership, consistent with the current Bridger plant ownership agreement with Idaho Power Company. Thus, these plants have capacities of 383 MW and 575 MW for a total capacity of 958 MW. A transmission upgrade was included between the Jim Bridger, Wyoming and Utah-North transmission areas. This portfolio will test the result of replacing the wet cool CCCT with the additional Wyoming coal resource, which may result in lower emissions cost credits and higher capital costs. However, the higher capacity factor of the coal resource combined with the transmission upgrade could prove to be economically desirable.

Table 7.5 – Portfolio Q: Transmission Expansion with Additional Wyoming Pulverized Coal

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									958		958
	Dry Cool CCCT w/ DF	Utah-S				525							525
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								194			194

<u>Portfolio Category: Technology Change</u>

This category looks at plant technology differences for a given fuel type. The two technology changes of interest were to compare gas-fired combined-cycle plants with IC Aero units, and to compare IGCC plants with pulverized coal plants. This will provide insight into which technology combination yields the lower-cost portfolios.

For the portfolio shown in Table 7.6, the FY 2009 Utah CCCT in the Reference Portfolio was replaced with multiple IC Aero units yielding a similar capacity size. Once again, the idea is to see how multiple simple-cycle units perform compared to a combined-cycle unit.

Table 7.6 – Portfolio C: Replace FY2009 CCCT with IC Aeros

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S						575					575
	Greenfield IGCC	WY										368	368
	Wet Cool CCCT w/ DF	Utah-N									560		560
	IC Aero SCCT	Utah-N				522							522
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Portfolios E, J, K, & L (Tables 7.7 – 7.10) were created to determine the cost and operational impacts of replacing the FY 2015 Wyoming IGCC in the initial portfolios (Portfolios A through D) is replaced with a Wyoming pulverized coal plant. Since the IGCC has less efficient operating characteristics and higher capital costs than the pulverized coal plants, the hypothesis is that the new portfolio will result in a lower PVRR. To maintain comparability with the IGCC unit, PacifiCorp assumed a two-thirds ownership share of the 575 MW pulverized coal resource, resulting in an effective size of 383 MW. This two-thirds ownership also applied to the transmission, consistent with the current Bridger plant ownership with Idaho Power Company.

Table 7.7 – Portfolio E: Portfolio A, with Wyoming PC replacing IGCC

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
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Table 7.8 – Portfolio J: Portfolio B, with Wyoming PC replacing IGCC

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	WY										383	383
	Dry Cool CCCT w/ DF	Utah-S				525		525					1050
	Wet Cool CCCT w/ DF	Utah-N									560		560
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								194			194

Table 7.9 – Portfolio K: Portfolio C, with Wyoming PC replacing IGCC

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
	Wet Cool CCCT w/ DF	Utah-N									560		560
	IC Aero SCCT	Utah-N				522							522
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								194			194

Table 7.10 – Portfolio L: Portfolio D, with Wyoming PC replacing IGCC

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
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								194			194

The portfolio depicted in Table 7.11 is derived from Portfolio M with the FY 2009 Utah CCCT being replaced with multiple IC Aero units yielding a similar capacity size. It was observed in portfolio C that making this substitution resulted in a lower PVRR. Thus, the idea was to see if the same substitution would similarly improve the All Gas portfolio (M). Another purpose for developing this portfolio was to analyze, via Stochastic and Scenario risk analysis, an additional portfolio with high risk exposure to fuel and power markets.

Table 7.11 – Portfolio N: All Gas with IC Aeros

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Dry Cool CCCT w/ DF	Utah-S						525					525
	Wet Cool CCCT w/ DF	Utah-N									560	560	1120
	IC Aero SCCT	Utah-N				522							522
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								194			194

Derived from Portfolio K, Portfolio O, shown in Table 7.12, was developed to test the result of building two IGCC plants in FY 2014 and FY 2015. The original FY 2015 IGCC plant is built in Wyoming, and the other replaces the brownfield pulverized coal unit in Utah.

Table 7.12 – Portfolio O: Utah & Wyoming IGCC

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Greenfield IGCC	Utah-S									368		368
	Greenfield IGCC	WY										368	368
	IC Aero SCCT	Utah-N										174	174
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N						560					560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

<u>Portfolio Category: Sequencing of Plants</u>

The purpose of this category was to analyze the impact of changing the sequence of coal and gas plant additions. Portfolio D in Table 7.13 tests the effect on PVRR from swapping the build years for the FY 2011 brownfield coal plant and the FY 2014 wet cool CCCT originally in Portfolio A. This tests the effect of deferring the higher capital cost coal resource and building a higher variable cost combined-cycle plant earlier.

Table 7.13 – Portfolio D: Defer Utah PC, Replace w/ WC-CCCT

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S									575		575
	Greenfield IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N						560					560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Portfolio Category: Location Change

This category contains two portfolios that test the impacts of a change in the location of the resource addition.

The portfolio in Table 7.14 relocates the Reference Portfolio's pulverized coal unit in FY 2011 to Wyoming. The plant is assumed to be near the existing Bridger units. PacifiCorp assumed a two-thirds ownership share of both plant and transmission, consistent with the current Bridger plant ownership agreement with Idaho Power Company.

Table 7.14 – Portfolio F: Transmission Expansion (Utah vs. Wyoming Coal Resource Location)

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Wyoming						383					383
	Greenfield IGCC	Wyoming										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N									560		560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Other portfolios in this analysis assume a consistent build pattern in the west of a wet cool CCCT and two IC Aero units in FY 2013. Portfolio G in Table 7.15 looks at the result of moving those IC Aero units to the east. This tests whether the benefit of lower forecasted gas prices in the east relative to the west offsets the higher fixed and variable O&M costs associated with building these units in the east.

Table 7.15 – Portfolio G: Build on East Side versus West Side

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S						575					575
	Greenfield IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N									560		560
	IC Aero SCCT	Utah-N								174			174
West	Dry Cool CCCT w/ DF	WMAIN								586			586

Portfolio Category: Storage Technologies

Portfolios in this category include units that use off-peak power to store electricity for predominately peaking capacity requirements. Technologies considered include Compressed Air Energy Storage (combined with a gas turbine for power generation) and Pumped Storage Hydroelectricity.

Portfolio H in Table 7.16 tests the effect of replacing the FY 2014 wet cool CCCT in the Reference Case with a Compressed Air Energy Storage unit. This portfolio assumes that a suitable air storage cavern is available.

Table 7.16 – Portfolio H: Replace FY2014 CCCT with Compressed Air Energy Storage

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S						575					575
	Greenfield IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Compressed Air ES	WY									323		323
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Portfolio I in Table 7.17 tests the effect of replacing the FY 2014 wet cool CCCT in the Reference Portfolio with a pumped storage hydroelectric unit. It is expected that the pumped hydroelectric unit will have a lower capacity factor than the replaced combined-cycle unit as well as higher capital costs.

Table 7.17 – Portfolio I: Replace FY2014 CCCT with Pumped Storage Hydro

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S						575					575
	Greenfield IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Pumped Hydro	Utah-N									400		400
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

<u>Portfolio Category: Capacity Expansion Model (CEM)</u>

This category consists of a single portfolio developed using the Capacity Expansion Model. The purpose of this portfolio was to validate the CEM against the manual portfolio build method.

Portfolio P, outlined in Table 7.18 below, has many features that are similar to the manually built portfolios, which is encouraging because it verifies that the manually built portfolios are providing solutions that are close to the mathematical least cost solution. Similarities include the large gas additions in the east in FY 2009 and 2015, and in the west in FY 2013. The noticeable differences were a larger number of IC Aero SCCT units spread among more years, and deferral of the Utah brownfield coal plant to FY 2012.

Table 7.18 – Portfolio P: CEM-Selected 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
	Dry Cool CCCT w/ DF	Utah-S				525						525	1050
	IC Aero SCCT	Utah-N									261		261
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)						97			97	97	291

STRESS CASE PORTFOLIOS

Six stress case portfolios were developed and evaluated. It is important to understand that these six portfolios are not candidates to be the Preferred Portfolio. Instead, they are “what-if” scenarios to help understand what will result from changing certain base assumptions.

A 15% planning margin was assumed for the 2004 IRP based upon the results of a system reliability study described in Appendix N. However, there was interest in determining the impacts of alternative planning margin levels. Thus, it was decided to take a look at what would happen if an 18% planning margin was assumed. Accordingly, the portfolio in Table 7.19 was derived from the Reference Portfolio (A) using additional resources to allow for this larger planning margin. Additional IC Aero units were built in the east to create this larger margin.

Table 7.19 – 18% PM 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
	Greenfield IGCC	Utah-N										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N									560		560
	IC Aero SCCT	Utah-N					174			174			348
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Similarly, there was interest in testing the scenario of having a smaller planning margin so a portfolio was derived from the Reference Portfolio (A) to reflect a 12% case. It resulted in the portfolio depicted in Table 7.20 which has one less combined-cycle plant and more IC Aero units in the east. In addition, there was one less IC Aero unit in the west as well.

Table 7.20 – 12% PM 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
	Greenfield IGCC	WY										368	368
	Wet Cool CCCT w/ DF	Utah-N									560		560
	IC Aero SCCT	Utah-N					87		87	87			261
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN										97	97

Front Office Transactions were included as a Planned Resource in the IRP (see Chapter 3 for details) and therefore were included in all of the portfolios that are candidates to be the Preferred Portfolio. There was interest in comparing Reference Portfolio (A) to a portfolio without Front Office Transactions. The resulting portfolio, shown in Table 7.21, was originally derived from the Reference Portfolio (A) and required three additional combined-cycle plants to replace the transactions.

Table 7.21 – Replace Front Office Transactions

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-S						575					575
	Greenfield IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525				525			1050
	Wet Cool CCCT w/ DF	Utah-N				560							560
West	Dry Cool CCCT w/ DF	WMAIN				586				586			1172
	IC Aero SCCT	WMAIN										194	194

Subsequent to the initial evaluation of portfolios with coal-fired IGCC units, new technology characteristics and market development activity prompted interest in analyzing a new IGCC portfolio. This portfolio assumed that PacifiCorp could procure a commercially viable IGCC unit within an optimistic timeframe, and with an updated design configuration and associated cost and operational parameters. (See Chapter 6 for background on the new IGCC technology assumptions.) The stress portfolio, based originally on Portfolio E, has a 460 MW IGCC unit replacing the pulverized coal unit in FY 2011. Table 7.22 shows the resulting stress case portfolio.

Table 7.22 – Early IGCC Commercial Viability

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Greenfield IGCC	Utah-S						460					460
	Brownfield Coal	WY										383	383
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N									560		560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

In the stress case portfolio shown in Table 7.23, which was derived from Portfolio E, 90 MW of CHP was added to the west system in FY 2013. This generation addition reduced the need for IC Aero SCCT units in the west from two to one 97 MW unit.

Table 7.23 – Portfolio E with West CHP

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Brownfield Coal	Utah-N						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
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								97			97
	CHP (2x45MW)	WMAIN								90			90

In the stress case portfolio shown in Table 7.24, which was derived from Portfolio E, 25% of the approximately 300 MW of standby generation in the Utah service area is assumed to be under PacifiCorp's dispatch control in FY 2009. This additional 75 MW of generation delays the need for a dry cool CCCT scheduled for FY 2009 in Portfolio E until FY 2010. The installation of the coal unit in FY 2011 can also be delayed by one year to FY 2012 while maintaining the 15% planning margin criteria.

In addition to generators in the east, 40 MW of standby generation is added to PacifiCorp's west control area in FY 2013. This 40 MW decreases the need for IC Aero units in the west from two to one 97 MW unit.

Table 7.24 – Portfolio E with Customer Standby Generation

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
	Standby Generation	East				75							75
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								97			97
	Standby Generation	West								40			40

SUMMARY

This chapter provided an overview of the different resource portfolios PacifiCorp developed in order to identify the Preferred Portfolio or assess alternative portfolio design assumptions (stress case portfolios). A Reference Portfolio was created and additional portfolios derived by generally changing one element of the Reference Portfolio to test specific resource type, sizing and timing effects. Six stress case portfolios were also created to analyze “what-if” scenarios that could result from changing certain base portfolio design assumptions. The next chapter discusses the results of simulating the PacifiCorp system with each of these portfolios, as well as the process used to select the preferred supply side portfolio and the final Preferred Portfolio.

8. RESULTS

INTRODUCTION

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

Discussion of the results falls into the following seven sections.

- **Candidate Portfolio Evaluation Results:** This section presents the expected costs of each candidate portfolio based on deterministic ("non-probabilistic") simulations. From these results, a set of portfolios is recommended for risk evaluation.
- **Risk Evaluation Results:** Risk evaluation summarizes portfolio cost variability due to the Stochastic and Scenario risks discussed in Chapter 4.
- **Customer Impacts:** The customer impacts section expresses portfolio cost results from the perspective of incremental rate impact for customers.
- **Selection of the Preferred Supply Side Portfolio:** This section provides a consolidated view of all the portfolio evaluation results to indicate which supply side portfolio is the most desirable after considering several risk measures and the tradeoff between low cost and low risk.
- **Class 1 DSM Analysis:** This section presents PacifiCorp's preferred IRP portfolio after the addition of dispatchable (Class 1) DSM programs.
- **DSM Decrement Analysis:** This section presents the decrement values for Class 2 program evaluations based on the Preferred Portfolio.
- **Stress Case Portfolio Evaluation Results:** This section presents the expected costs of portfolios designed for sensitivity analysis of certain portfolio assumptions. These assumptions include alternative Planning Margin levels[13] (12 percent and 18 percent), replacement of Front Office Transactions with build-or-buy assets, early IGCC commercial viability, and the inclusion of CHP and stand-by generators as resource options for the preferred supply side portfolio.

CANDIDATE PORTFOLIO EVALUATION RESULTS

This section presents deterministic simulation results, and describes how these results were used to select portfolios for risk analysis. It summarizes cost and operational performance by portfolio type, as well as overall portfolio performance.

[13] The 18% and 12% Planning Margin stress portfolios were also evaluated stochastically; the stress case analyses only report the deterministic simulation results.

Portfolio Type Results

PacifiCorp initially created eight portfolios to analyze resource type, timing, and location impacts with respect to Reference Portfolio A. This section summarizes these results. The portfolio comparisons include the following (Table 8.1):

Table 8.1 – Initial Portfolio Comparison Types and Portfolios

Comparison Type	Comparison Portfolio
Fuel Type: Gas versus Coal Resource	**B:** Remove FY 2011 Utah Pulverized Coal, Replace w/ DC-CCCT
Gas Technology Type: CCCT versus IC Aero SCCT Resource	**C**: Replace FY 2009 CCCT with Aeros
Coal Technology Type: Pulverized Coal versus IGCC Resource	**E**: Replace FY 2015 IGCC with WY Pulverized Coal
Large Resource Build Sequence: Coal versus CCCT Resource	**D**: Defer FY 2011 Utah Pulverized Coal, Replace with WC-CCCT
Utah versus Wyoming Coal Resource Location and New Transmission	**F**: Transmission Expansion
East-Side versus West-Side Resource Location of IC Aero SCCT Resource	**G**: Build on East Side vs. West Side
Storage Technology Type: Compressed Air Energy Storage	**H**: Replace FY 2014 CCCT with Compressed Air Energy Storage
Storage Technology Type: Pumped Storage Hydroelectric	**I**: Replace FY 2014 CCCT with Hydro Pumped Storage

As mentioned in Chapter 5, the principal measure of overall portfolio performance is the Present Value Revenue Requirement, or PVRR. As a reminder, this measure captures the discounted, levelized sum of annual nominal-dollar revenues required for system operations and the capital costs for new IRP proxy resources. Also note that all data are reported in a fiscal year basis unless stated otherwise.

Fuel Type: Gas versus Coal Resource

For this comparison involving Portfolio B and A, the Utah pulverized coal resource is replaced with a second dry cool CCCT in FY 2011. Based on the total PVRR, the Reference Portfolio performs slightly better than Portfolio B, but the difference is small at only $24 million, or a 0.2% difference. Table 8.2 shows the breakdown of each portfolio's PVRR by variable and fixed cost components. The swing factor is the total fuel cost. Although Portfolio B has a much lower fixed cost, the relatively higher fuel cost gives the PVRR edge to the reference case. For example, in FY 2015, the Utah coal resource had an average variable cost of $12.18/MWh compared to $40.07/MWh for the CCCT resource. Other notable observations include the following:

- As expected, Portfolio B had a larger emissions cost credit ($166.4 million) due to the lower emission rates for the CCCT technology.
- The PacifiCorp system under Portfolio B had $53.0 million less in sales and $64.3 million more in purchases.

Table 8.2 – Portfolio PVRR Cost Component Comparison: Gas vs. Coal Resource

COST COMPONENT ($000)	B	Reference A	Difference (B - A)	Percent Difference
Variable Costs				
Total Fuel Cost	11,123,111	10,568,841	554,270	5.2%
Total Variable O&M Cost	1,078,600	1,021,323	57,277	5.6%
Total Emissions Cost	(626,370)	(459,986)	(166,384)	36.2%
Total Start-up Cost	10,426	11,014	(588)	(5.3%)
Variable Contract Cost	1,808,860	1,798,135	10,724	0.6%
Sales	(3,610,727)	(3,663,728)	53,001	(1.4%)
Purchases	1,730,199	1,665,937	64,263	3.9%
Total Net Variable Power Cost	11,514,098	10,941,536	572,563	5.2%
Real Levelized Fixed Cost	1,884,045	2,432,635	(548,590)	(22.6%)
TOTAL PVRR	13,398,143	13,374,170	23,973	0.2%

Portfolio B exhibits a slightly higher utilization of existing coal resources, and significantly higher utilization of gas-fired units, relative to Portfolio A. In Portfolio A, the Utah brownfield resource displaces existing gas units due to a much lower production cost; this is not a factor for Portfolio B. Figure 8.1 shows the annual capacity utilization trends for existing coal and gas resources under both portfolios.[14] The measure used is the capacity factor[15], which is calculated as the sum of annual generation divided by the sum of possible annual generation for each resource reporting category.

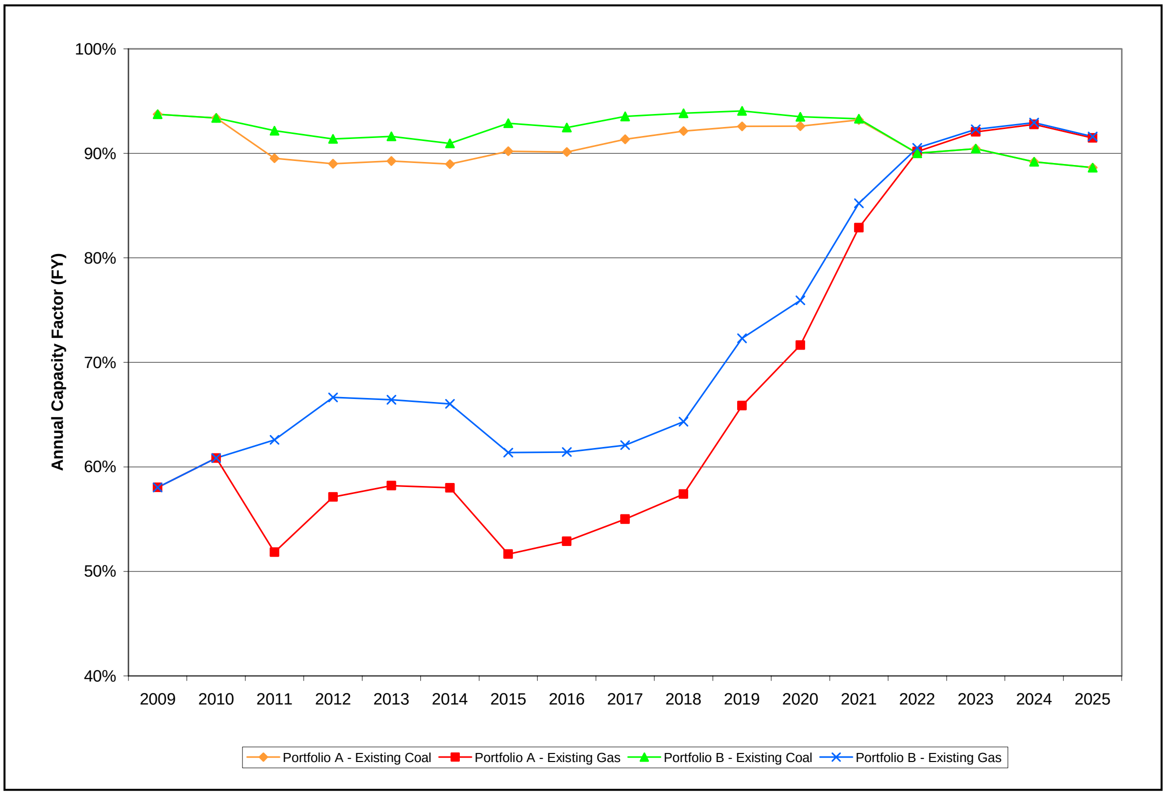
Gas Technology Type: CCCT versus IC Aero SCCT

For this comparison involving Portfolios A and C, six IC Aero SCCT units replace the single Utah dry cool CCCT unit in FY 2009. Based on PVRR, Portfolio C performs slightly better than the Reference Portfolio, with a difference of $9.6 million, or less than 0.1%. Table 8.3 shows the breakdown of each portfolio's PVRR by cost component.

There isn't a single factor that drives relative cost performance between the two portfolios. Portfolio C's production costs – fuel, variable O&M, emissions, and start-up – are all lower than those for A, but Portfolio C incurs a higher net variable power cost due to relatively greater purchase and variable contract costs, and lower sales revenues. Portfolio C's fixed cost is lower than that for Portfolio A, a result in line with the SCCT's lower per-kW capital cost; $560/kW versus $587/kW for the CCCT.

[14] Note that in accordance with the firm transmission rights market constraint outlined in the System Topology section of Chapter 3, capacity utilization trends shown in this chart and others in this document reflect a conservative market size assumption that doesn't account for non-firm transmission or opportunities to make additional market sales and purchases.
[15] Possible generation reflects thermal unit capacities derated for planned and unplanned outages.

Figure 8.1 – Utilization Trends for Existing Resources: Portfolio A vs. Portfolio B



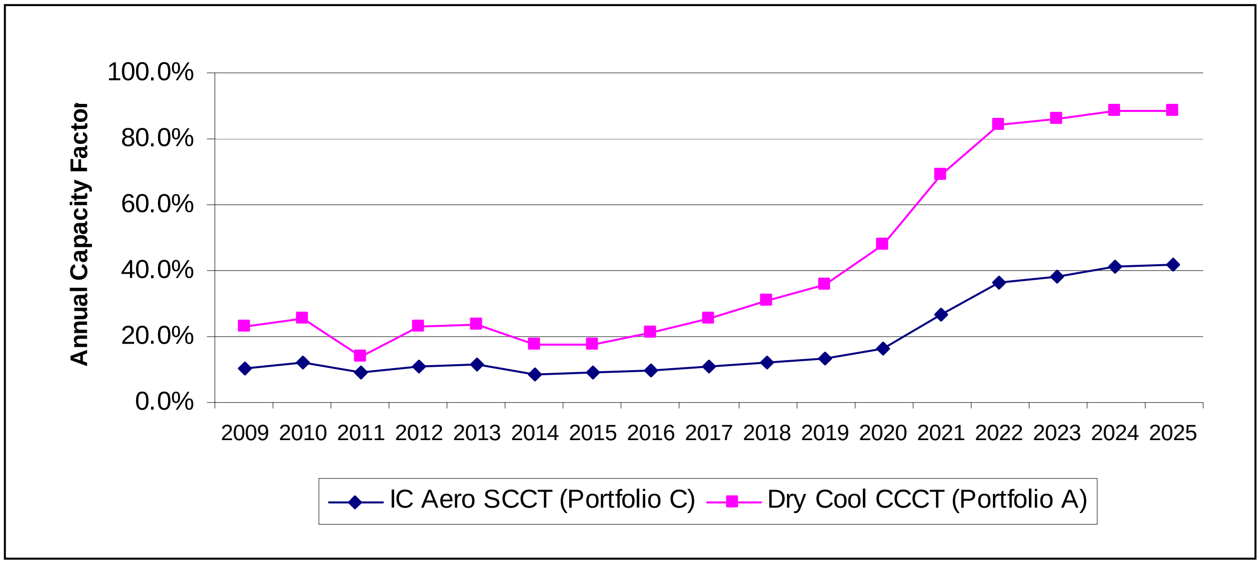
The variable cost differences are largely driven by the lower utilization rate for the Simple Cycle units with respect to the CCCT; the average annual capacity factor for the Simple Cycle units is about 24 percent lower than that of the CCCT over the study period. Figure 8.2 shows the annual capacity factors for Portfolio A's CCCT and Portfolio C's Simple Cycle units. Portfolio C results in slightly greater utilization of existing gas resources relative to Portfolio A; the difference is about 1.5 percentage points per year throughout the study period. The relative impact of the IC Aero SCCTs on existing coal units is negligible.

Table 8.3 – Portfolio PVRR Cost Components: CCCT vs. IC Aero SCCT

COST COMPONENT ($000)	C	Reference A	Difference (C - A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,447,627	10,568,841	(121,214)	(1.1%)
Total Variable O&M Cost	1,019,905	1,021,323	(1,417)	(0.1%
Total Emissions Cost	(463,782)	(459,986)	(3,796)	0.8%
Total Start-up Cost	10,597	11,014	(416)	(3.8%)
Variable Contract Cost	1,822,333	1,798,135	24,198	1.3%
Sales	(3,603,459)	(3,663,728)	60,269	(1.6%)
Purchases	1,781,745	1,665,937	115,808	7.0%
Total Net Variable Power Cost	11,014,967	10,941,536	73,431	0.7%
Real Levelized Fixed Cost	2,349,640	2,432,635	(82,995)	(3.4%)

COST COMPONENT ($000)	C	Reference A	Difference (C - A)	Percent Difference
TOTAL PVRR	13,364,607	13,374,170	(9,564)	(0.1%)

Figure 8.2 – Capacity Factor Comparison: CCCT Portfolio A vs. IC Aero Portfolio C



Coal Technology Type: Pulverized Coal versus Integrated Gasification Combined Cycle
For this comparison, the 368 MW Wyoming IGCC resource added in FY 2015 for Portfolio A was replaced with a pulverized coal resource.[16] To maintain comparability with the IGCC unit, PacifiCorp assumed a two-thirds ownership share of the 575 MW pulverized coal resource consistent with the current Idaho Power Company agreement, resulting in an effective size of 383 MW. (Two-thirds ownership of associated transmission upgrades was also assumed.) Table 8.4 shows the relative variable and fixed PVRR cost components for Portfolios E and A. Portfolio E's total PVRR is lower by 89.6 million, or 0.7 percent. The main contributor to the cost difference is the IGCC unit's higher plant construction cost: $2,171/kW versus $1,813/kW for the pulverized coal unit. Portfolio A's total fixed cost is $48.6 million higher than that for Portfolio E, even accounting for the IGCC unit's lower fixed O&M cost.

The net variable power cost is also in Portfolio E's favor. The only cost component for which Portfolio A's value exceeds that of Portfolio E's value is the total emissions cost. The lower emission rates for SO_2 and NO_X contribute to the larger emissions cost credit. The cost credit difference is $33.3 million, or 7.2 percent. Spot market purchases represent the second largest cost differential after fixed costs, providing Portfolio E with a $48.0 million relative advantage.

[16] See Chapter 6 for IGCC technology assumptions used for portfolio analysis. Note that only the stress test IGCC portfolio described later in this Chapter was modeled using updated assumptions.

Table 8.4 – Portfolio PVRR Cost Components: Pulverized Coal vs. IGCC

COST COMPONENT ($000)	E	Reference A	Difference (E - A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,568,614	10,568,841	(228)	0.0%
Total Variable O&M Cost	1,004,686	1,021,323	(16,637)	(1.6%)
Total Emissions Cost	(426,657)	(459,986)	33,328	(7.2%)
Total Start-up Cost	10,969	11,014	(44)	(0.4%)
Variable Contract Cost	1,789,441	1,798,135	(8,694)	(0.5%)
Sales	(3,664,543)	(3,663,728)	(815)	0.0%
Purchases	1,617,947	1,665,937	(47,990)	(2.9%)
Total Net Variable Power Cost	10,900,457	10,941,536	(41,075)	(0.4%)
Real Levelized Fixed Cost	2,384,066	2,432,635	(48,569)	(2.0%)
TOTAL PVRR	13,284,523	13,374,170	(89,647)	(0.7%)

Average annual per-MWh variable costs for the IGCC and pulverized coal proxy resources are about equal, with IGCC having a slight advantage for total variable cost as shown in Table 8.5 below:

Table 8.5 – Variable Cost Comparison, Wyoming Pulverized Coal vs. IGCC

Unit	Average Annual Variable Costs ($/MWh). FY 2014 – 2025		
	Fuel	**Variable O&M**	**Total Variable**
Wyoming Pulverized Coal (from Portfolio E)	15.29	1.18	16.47
Wyoming IGCC (from Portfolio A)	13.54	2.71	16.25

The IGCC resource has a higher assumed capacity de-rate for total outages—25%, compared with 9% for pulverized coal and 7.75% for CCCTs—forcing higher utilization of other gas units to compensate. This accounts for the lack of a portfolio-wide fuel cost benefit from using less expensive coal. For example, Portfolio A's annual capacity factor for existing gas units in FY 2015 is about two percentage points higher than the capacity factor for Portfolio E. Differences between the Portfolio's coal unit capacity factors are negligible.

The conclusion from this portfolio comparison is that an IGCC resource is not as cost-effective as a pulverized coal resource due to its higher capital cost and outage rate. This conclusion was further substantiated by conducting this IGCC resource substitution test with three other portfolios (B, C, and D). The simulation results for the resulting new portfolios— J, K, and L — are described later in this Chapter.

Resource Build Sequence: Coal versus CCCT Resource

For this comparison, the order of the second resource added in Utah is reversed; the wet cool CCCT is moved up from FY 2014 to FY 2011, while the brownfield pulverized coal resource is deferred from FY 2011 to FY 2014. This comparison between Portfolios A and D is meant to gauge the timing impacts for a resource with relatively higher capital cost (coal) versus a resource with relatively higher production costs (gas).

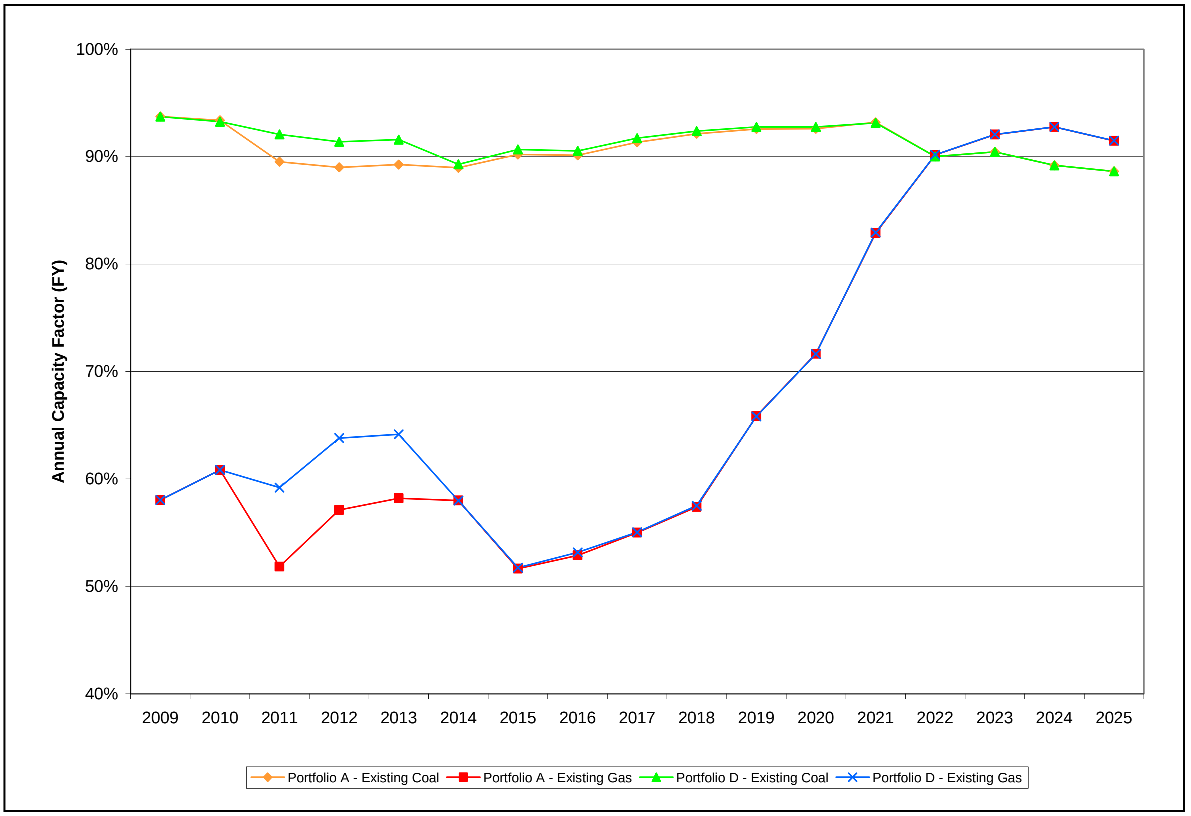
Table 8.6 shows the variable and fixed PVRR cost components for the two portfolios. The negligible difference in total PVRRs—only $2.0 million—indicates that there is effectively no net cost savings by changing the build sequence of these particular coal and gas proxy resources. The higher net variable power cost for Portfolio D offsets the higher fixed cost for Portfolio A.

Table 8.6 – Portfolio PVRR Cost Components: Build Sequence, Coal vs. CCCT

COST COMPONENT ($000)	D	Reference A	Difference (D - A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,727,911	10,568,841	159,070	1.5%
Total Variable O&M Cost	1,035,864	1,021,323	14,541	1.4%
Total Emissions Cost	(483,579)	(459,986)	(23,593)	5.1%
Total Start-up Cost	10,681	11,014	(332)	(3.0%)
Variable Contract Cost	1,799,758	1,798,135	1,623	0.1%
Sales	(3,656,956)	(3,663,728)	6,772	(0.2%)
Purchases	1,671,634	1,665,937	5,697	0.3%
Total Net Variable Power Cost	11,105,313	10,941,536	163,784	1.5%
Real Levelized Fixed Cost	2,270,882	2,432,635	(161,753)	(6.6%)
TOTAL PVRR	13,376,195	13,374,170	2,025	0.0%

For existing resources, there is a significant difference in utilization rates between the two portfolios from FY 2011 through FY 2014. The earlier CCCT unit in Portfolio D displaces less coal and gas generation than the pulverized coal unit in Portfolio A. This difference vanishes when the pulverized coal resource comes on line in FY 2014. Figure 8.3 shows the portfolio annual capacity factor trends for existing coal and gas resources.

Figure 8.3 – Utilization Trends for Existing Resources: Portfolio A vs. Portfolio D



Utah versus Wyoming Coal Resource Location and New Transmission

As mentioned in Chapter 7, Portfolio F entails substituting the FY 2011 Utah pulverized coal unit with a Wyoming unit and building additional transmission capacity. Compared to Portfolio A, this Portfolio is less economic: $13.49 billion PVRR for Portfolio F versus a $13.37 billion PVRR for Portfolio A ($116.8 million difference). The main driver for the PVRR difference is the capital cost of the IGCC resource added in FY 2015. Table 8.7 shows the variable and fixed PVRR cost components for the two portfolios.

Table 8.7 – Portfolio PVRR Cost Components: Utah vs. Wyoming Coal/Transmission Resources

COST COMPONENT ($000)	F	Reference A	Difference (F - A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,628,233	10,568,841	59,392	0.6%
Total Variable O&M Cost	1,027,476	1,021,323	6,153	0.6%
Total Emissions Cost	(518,395)	(459,986)	(58,409)	12.7%
Total Start-up Cost	11,357	11,014	343	3.1%
Variable Contract Cost	1,785,397	1,798,135	(12,738)	(0.7%)
Sales	(3,537,530)	(3,663,728)	126,198	(3.4%)
Purchases	1,785,510	1,665,937	119,573	7.2%
Total Net Variable Power Cost	11,182,048	10,941,536	240,513	2.2%

COST COMPONENT ($000)	F	Reference A	Difference (F - A)	Percent Difference
Real Levelized Fixed Cost	2,308,951	2,432,635	(123,684)	(5.1%)
TOTAL PVRR	13,490,999	13,374,170	116,829	0.9%

There is little difference in resource utilization rates between the two portfolios; Portfolio F's existing gas units have a slightly higher capacity factor beginning in FY 2011. This difference is due to the MW capacity difference of the resources added in that year: 383 MW for Portfolio F versus 575 MW for Portfolio A.

Transfers for the two portfolios differ substantially due to the east versus west location impact of the coal resource added in FY 2011. This is mainly due to the fact that Bridger is considered a western resource, and additional transmission is built to import Bridger to the east. West-to-east transfers increase dramatically for Portfolio F as the system takes advantage of the availability of lower-cost Wyoming power; in contrast, the west-to-east transfers decrease slightly for Portfolio A until FY 2014. Figure 8.4 shows the control area transfer trends for each portfolio.

Figure 8.4 – Control Area Transfer Trends: Portfolio A vs. Portfolio F

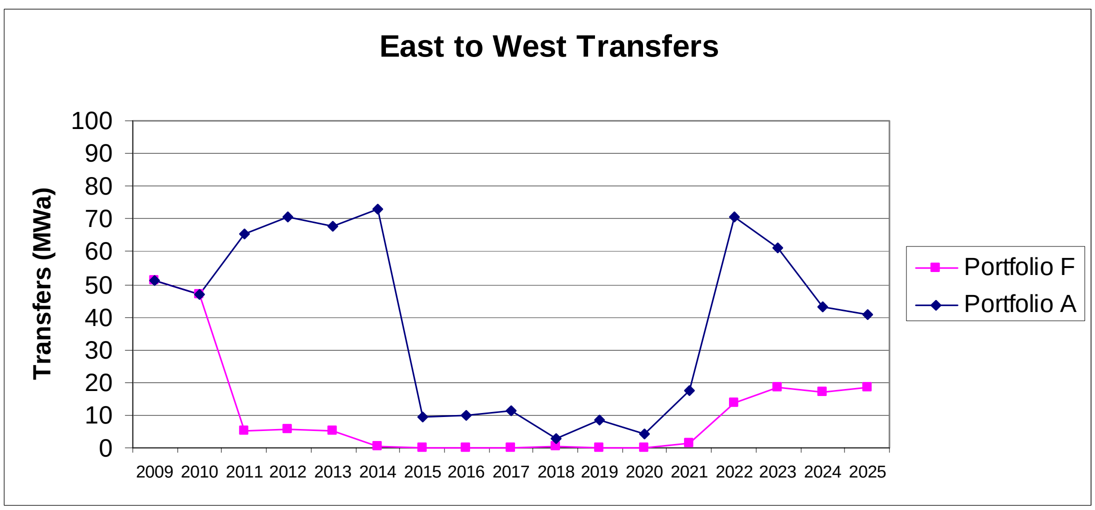
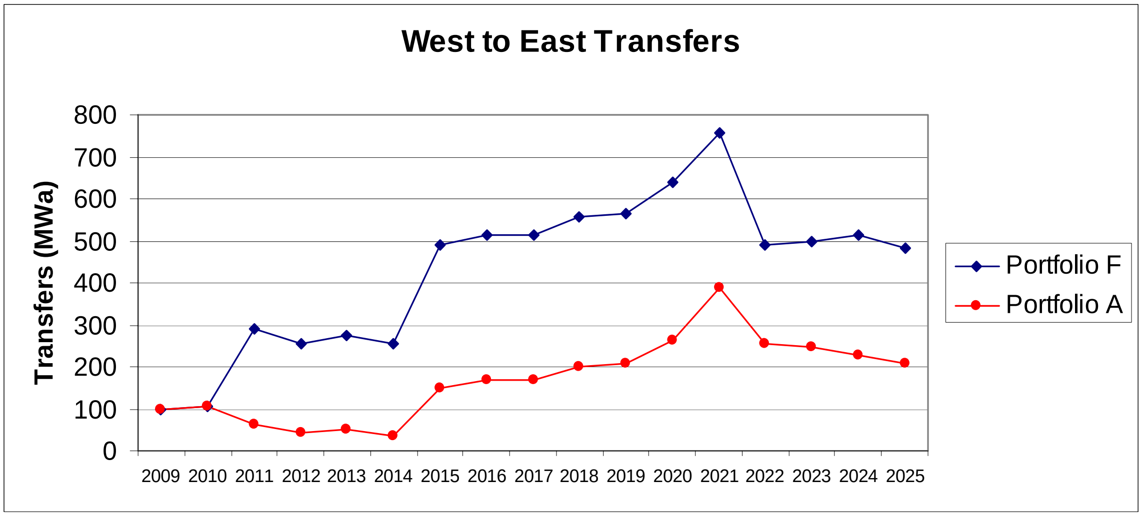


Figure 8.4 – Control Area Transfer Trends: Portfolio A vs. Portfolio F, Continued



East-Side versus West-Side Location of IC Aero SCCT Resource

For this comparison, two FY 2013 IC Aero SCCT units added in the west for Portfolio A are added to the east instead. This tests whether the benefit of lower forecasted gas prices in the east relative to the west offsets the higher fixed and variable O&M costs associated with building these units in the east. The unit costs for each IC Aero SCCT resource are shown in table 8.8.

Table 8.8 – Unit Cost Comparison, East-side vs. West-side IC Aero SCCT Installation

Cost Component	East-Side	West-Side
Capital Cost	$560/kW	$501/kW
Variable O&M	$4.20/MWh	$3.76/MWh
Fixed O&M	$9.05/kW-yr	$8.10/kW-yr

The simulation results show that the west to east location change of the IC Aero SCCTs increases costs; Portfolio G's PVRR is $11.8 million higher. Table 8.9 shows the variable and fixed PVRR cost components for the two portfolios. The fixed cost superiority of Portfolio A swings the overall PVRR to Portfolio A's favor, although Portfolio' G's greater spot market sales in the east narrows the cost difference considerably.

Table 8.9 – Portfolio PVRR Cost Components: East vs. West Resource Location

COST COMPONENT ($000)	G	Reference A	Difference (G - A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,569,023	10,568,841	182	0.0%
Total Variable O&M Cost	1,022,353	1,021,323	1,030	0.1%
Total Emissions Cost	(459,412)	(459,986)	574	(0.1%)
Total Start-up Cost	10,742	11,014	(271)	(2.5%)
Variable Contract Cost	1,809,651	1,798,135	11,515	0.6%
Sales	(3,678,781)	(3,663,728)	(15,053)	0.4%
Purchases	1,663,308	1,665,937	(2,628)	(0.2%)

COST COMPONENT ($000)	G	Reference A	Difference (G - A)	Percent Difference
Total Net Variable Power Cost	10,936,884	10,941,536	(4,651)	0.0%
Real Levelized Fixed Cost	2,449,112	2,432,635	16,477	0.7%
TOTAL PVRR	13,385,996	13,374,170	11,826	0.1%

A comparison of each portfolio's IC Aero SCCT costs and annual capacity factors is shown in Table 8.10. As expected, the eastern IC Aero SCCTs have a lower fuel cost and higher variable O&M cost relative to the western IC Aero SCCTs. Annual capacity factors for the eastern IC Aero SCCTs are lower than those for the western units initially. However, a cross-over point in FY 2019 occurs; the capacity factors for the east then exceed those of the western units for the duration of the study period, with the difference widening to over 12 percentage points by FY 2024. Switching unit location has a negligible impact on the capacity factors of existing coal and gas units.

Table 8.10 – Cost and Operational Comparison: East IC Aero SCCT vs. West IC Aero SCCT

Cost Component ($000) (Net Present Value)	IC Aero SCCT		Difference
	East Location 2 x 87 MW (Portfolio G)	West Location 2 x 97 MW (Portfolio A)	
Fuel Cost	97,630	99,336	(1,706)
Start Cost	252	354	(102)
VOM Cost	12,300	10,814	1,486
Total Emission Cost	11,684	11,472	213
	Annual Capacity Factor FY 2006 – FY 2025		
	20.1%	17.5%	2.6%

Control Area transfer differences between the two portfolios are minor, a result expected given the small size of the resource involved (174 MW). There is virtually no impact on east-to-west transfers until FY 2021, when three coal stations are slated for retirement (Jim Bridger, Dave Johnston, and Carbon). Portfolio G's west-to-east transfers are about 5 MWa higher in FY 2013, and increase to 10 MWa by FY 2015.

Storage Technology Type: Compressed Air Energy Storage

For this comparison between Portfolios A and H, a Compressed Air Energy Storage (CAES) system, combined with a simple cycle gas turbine, replaces Portfolio A's wet cool CCCT installed in Utah in FY 2014. The CAES portfolio assumes that a suitable air storage cavern is available. The PVRR results indicate that Portfolio H has a higher cost—by $118.1 million—driven by the low CAES plant utilization. The effects of low utilization are increased use of existing gas units and a higher spot market exposure on the purchase side. Table 8.11 shows the variable and fixed PVRR cost components for the two portfolios.

The variable cost for Portfolio H is higher than the cost for Portfolio A primarily because of less generation from the CAES resource relative to the CCCT unit in Portfolio A. However, examining per-MWh variable costs for the individual resources highlights the impact of the CAES unit's lower heat rate, which stems from the use of off-peak electricity to run the gas turbine's air compressor. For FY 2014 through FY 2025, the average annual variable cost for the CAES unit is $17/MWh lower than the cost for the CCCT from Portfolio A.

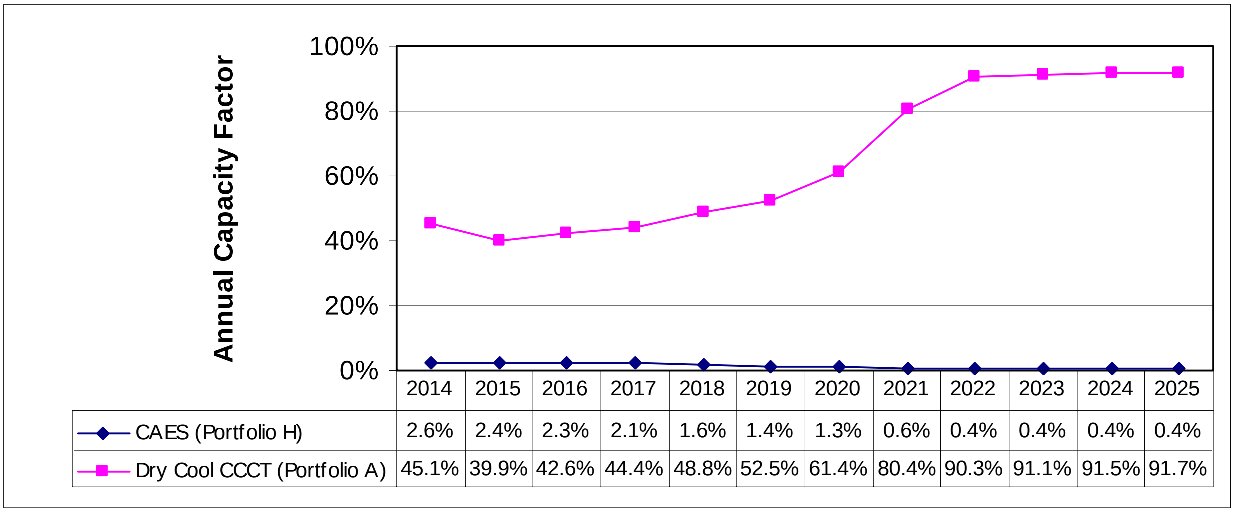
Table 8.11 – Portfolio PVRR Cost Components: CCCT vs. Compressed Air Energy Storage

COST COMPONENT ($000)	H	Reference A	Difference (H – A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,246,649	10,568,841	(322,192)	(3.0%)
Total Variable O&M Cost	990,371	1,021,323	(30,951)	(3.0%)
Total Emissions Cost	(491,569)	(459,986)	(31,583)	6.9%
Total Start-up Cost	11,527	11,014	514	4.7%
Variable Contract Cost	1,834,027	1,798,135	35,892	2.0%
Sales	(3,534,663)	(3,663,728)	129,065	(3.5%)
Purchases	2,011,963	1,665,937	346,026	20.8%
Total Net Variable Power Cost	11,068,306	10,941,536	126,771	1.2%
Real Levelized Fixed Cost	2,423,986	2,432,635	(8,649)	(0.4%)
TOTAL PVRR	13,492,292	13,374,170	118,122	0.9%

Figure 8.5 shows the capacity factor for the CAES resource versus the CCCT resource from Portfolio A. As expected, other gas-fired resources—and to a lesser extent, coal resources—make up for the relative generation shortfall. The capacity factor for existing gas units in Portfolio H starts out four percentage points higher than the capacity factor for Portfolio A, with the gap decreasing slightly over the course of the study period.

Beginning in FY 2014, Portfolio H's west-to-east transfers are higher, and east-to-west transfers lower, than the corresponding transfers for Portfolio A. This pattern reflects the availability of lower-cost electricity available from the west; output increases significantly in FY 2014 for such west-side units as the new dry cool CCCT resource (added in FY 2013), Hermiston 1, Colstrip 4, and Jim Bridger 4.

Figure 8.5 – Capacity Factor: CAES Resource Portfolio H vs. CCCT Portfolio A



The general conclusion to be made from the system simulation results is that CAES has economic advantages as a peak load resource, but it is not a cost-effective alternative to CCCTs unless there is significant underutilized baseload plant capacity or a very large expected spread between on-peak and off-peak incremental costs.

Storage Technology Type: Hydroelectric Pumped Storage

For this comparison between Portfolios A and I, a hydroelectric pumped storage (hydro PS) system replaces Portfolio A's wet cool CCCT installed in Utah in FY 2014. As with the CAES Portfolio, Portfolio I is not a cost-effective alternative to CCCTs. The overall cost characteristics are similar to the CAES portfolio in that Portfolio I's PVRR is higher than the PVRR for Portfolio A—by $160.4 million—attributable to the low plant utilization (about 8%) and much higher reliance on spot market purchases. However, whereas the CAES portfolio has a small relative advantage over Portfolio A with respect to the levelized fixed cost, the hydro PS portfolio has a significantly higher fixed cost, by $51.2 million. Table 8.12 shows the variable and fixed PVRR cost components for the two portfolios.

Table 8.12 – Portfolio PVRR Cost Components: CCCT vs. Hydro Pumped Storage

COST COMPONENT ($000)	I	Reference A	Difference (I - A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,251,245	10,568,841	(317,597)	(3.0%)
Total Variable O&M Cost	992,086	1,021,323	(29,237)	(2.9%)
Total Emissions Cost	(485,491)	(459,986)	(25,505)	5.5%
Total Start-up Cost	11,118	11,014	104	0.9%
Variable Contract Cost	1,822,433	1,798,135	24,297	1.4%
Sales	(3,540,461)	(3,663,728)	123,267	(3.4%)
Purchases	1,999,844	1,665,937	333,907	20.0%
Total Net Variable Power Cost	11,050,772	10,941,536	109,237	1.0%

COST COMPONENT ($000)	I	Reference A	Difference (I - A)	Percent Difference
Real Levelized Fixed Cost	2,483,814	2,432,635	51,179	2.1%
TOTAL PVRR	13,534,586	13,374,170	160,416	1.2%

Utilization trends for system resources are similar to that of the CAES portfolio. Control area transfers exhibit similar patterns as well.

Conclusions

Table 8.13 summarizes the main observations for each of the Phase I portfolio comparisons described above.

Table 8.13 – Portfolio Comparison Conclusions

Comparison Type	Comparison Portfolio	Observations
Fuel Type: Gas versus Coal Resource	**B:** Remove FY 2011 Utah Pulverized Coal, Replace w/ DC-CCCT	PVRR is about the same for these Utah coal and gas proxy resources, with a nominal edge given to coal. The high capital cost for the coal plant offsets its production cost advantage; in contrast, the high production cost for the gas plant offsets its low capital cost advantage.
Gas Technology Type: CCCT versus IC Aero SCCT Resource	**C**: Replace FY 2009 CCCT with Aeros	Equivalent PVRRs, but low utilization of IC Aero SCCTs means a much higher spot market purchase requirement.
Coal Technology Type: Pulverized Coal versus IGCC Resource	**E**: Replace FY 2015 IGCC with WY Pulverized Coal	Based on current technical expectations and performance guarantees, IGCC is not as cost-effective relative to a pulverized coal resource, due to lower utilization.
Large Resource Build Sequence: Coal versus CCCT Resource	**D**: Defer FY 2011 Utah Pulverized Coal, Replace with WC-CCCT	The build sequence has no material PVRR impact; the gas resource’s higher variable costs relative to the coal resource offsets lower relative fixed costs.
Utah versus Wyoming Coal Resource Location and New Transmission	**F**: Transmission Expansion	This transmission expansion portfolio is not cost effective due primarily to the high capital costs for plant and transmission.
East-Side versus West-Side Resource Location of IC Aero SCCT Resource	**G**: Build on East Side vs. West Side	Siting IC Aero SCCTs in the east, rather than the west, is not cost effective based on the gas price differential used for the simulations.
Storage Technology Type: Compressed Air Energy Storage	**H**: Replace FY 2014 CCCT with Compressed Air Energy Storage	CAES is shown to be economical as a flexible resource in relation to a CCCT, but is not a cost-effective portfolio resource due to low utilization.

Comparison Type	Comparison Portfolio	Observations
Storage Technology Type: Pumped Storage Hydroelectric	**I**: Replace FY 2014 CCCT with Hydro Pumped Storage	Hydro pumped storage is shown to be economical for peaking service in relation to a CCCT, but is not a cost-effective portfolio resource due to low utilization; CAES is preferred over hydro PS.

Phase II Candidate Portfolios

PacifiCorp conducted a second round of candidate portfolio development and testing (Phase II). The Phase II group of portfolios was composed with the following objectives in mind:

- Reduce portfolio PVRRs based on Phase I simulation results
- Ensure that a representative set of portfolio types is considered as candidates for risk analysis
- Test new portfolios stemming from portfolio design ideas and recommendations proposed by PacifiCorp staff and public participants in the IRP process.

IGCC Resource Replacement with Pulverized Coal Technology

The "Portfolio E versus Portfolio A" simulation comparison indicates that an IGCC resource is not as cost-effective as a conventional pulverized coal resource, based on current technical expectations and assumed performance guarantees. Therefore, PacifiCorp modified three of the Phase I portfolios that contain the Wyoming IGCC resource—B, C, and D—by replacing the IGCC unit with a sub-critical pulverized coal resource. The resulting new portfolios, J, K, and L, were simulated and compared against their corresponding originals to determine the net cost savings associated with the IGCC resource replacement. For these portfolios, PacifiCorp assumed a two-thirds ownership share of both plant and transmission, consistent with the current Bridger plant ownership agreement with Idaho Power Company. Table 8.14 compares the PVRR results of the portfolios with, and without, the IGCC resource. As shown, the average PVRR difference between the portfolios is over $92 million. Note that these cost results are predicated on preliminary cost and performance assessments, as discussed in Chapter 6. Also, potential cost savings for carbon capture and sequestration, relative to a conventional pulverized coal plant, are not factored into the simulations.

Table 8.14 – PVRR Comparisons: Portfolios with and without the Wyoming IGCC Resource

Portfolio Comparison	PVRR ($000)	PVRR ($000)	Difference
Portfolio A vs. Portfolio E	13,374,401	13,284,757	(89,644)
Portfolio B vs. Portfolio J	13,398,365	13,303,704	(94,661)
Portfolio C vs. Portfolio K	13,364,848	13,269,478	(95,369)
Portfolio D vs. Portfolio L	13,376,432	13,286,028	(90,175)
AVERAGE			(92,462)

All-Gas Portfolios

PacifiCorp developed two portfolios that included all gas-fired proxy resources. Portfolio M has all CCCT resources, whereas Portfolio N includes CCCTs and IC Aero SCCTs (See Chapter 7). The purpose of these two portfolios was to test the hypothesis that such all-gas portfolios should perform well on a PVRR basis, given their superior operating flexibility and large capital cost advantage relative to coal-dominated portfolios. A second purpose for developing these portfolios was to analyze, via Stochastic and Scenario risk analysis, portfolios with high risk exposure to fuel and power markets.

As expected, both all-gas portfolios had significantly lower PVRRs than Portfolio A. *Portfolio M also has the lowest PVRR of all the candidate portfolios tested*. Tables 8.15 and 8.16 show the PVRR cost components for the two portfolios compared to Portfolio A. The PVRR component breakdown exhibits the typical pattern for a coal versus gas portfolio resource comparison; the all-gas portfolios had a higher variable power cost, but lower fixed cost, relative to Portfolio A's mix of coal and gas resources.

Both all-gas portfolios have higher spot market exposure than Portfolio A. Portfolio M has higher market sales revenues than both Portfolios A and N, while Portfolio N has higher market purchase costs than Portfolios A and M. These relative market cost results are indicative of the higher off-peak energy balancing requirements for gas-dominated portfolios. This balancing requirement is even higher for gas-dominated portfolios with SCCT resources.

Table 8.15 – Portfolio PVRR Cost Components: Portfolio M vs. Portfolio A

COST COMPONENT ($000)	M	Reference A	Difference (M – A)	Percent Difference
Variable Costs				
Total Fuel Cost	11,492,964	10,568,841	924,122	8.7%
Total Variable O&M Cost	1,098,495	1,021,323	77,172	7.6%
Total Emissions Cost	(667,809)	(459,986)	(207,824)	45.2%
Total Start-up Cost	9,733	11,014	(1,281)	(11.6%)
Variable Contract Cost	1,792,566	1,798,135	(5,569)	(0.3%)
Sales	(3,699,120)	(3,663,728)	(35,392)	1.0%
Purchases	1,653,212	1,665,937	(12,724)	(0.8%)
Total Net Variable Power Cost	11,680,040	10,941,536	738,504	6.7%
Real Levelized Fixed Cost	1,575,567	2,432,635	(857,068)	(35.2%)
TOTAL PVRR	13,255,607	13,374,170	(118,563)	(0.9%)

Table 8.16 – Portfolio PVRR Cost Components: Portfolio N vs. Portfolio A

COST COMPONENT ($000)	N	Reference A	Difference (N - A)	Percent Difference
Variable Costs				
Total Fuel Cost	11,397,414	10,568,841	828,572	7.8%
Total Variable O&M Cost	1,097,127	1,021,323	75,804	7.4%
Total Emissions Cost	(674,392)	(459,986)	(214,406)	46.6%
Total Start-up Cost	9,611	11,014	(1,403)	(12.7%)
Variable Contract Cost	1,810,111	1,798,135	11,976	0.7%
Sales	(3,616,810)	(3,663,728)	46,919	(1.3%)
Purchases	1,732,091	1,665,937	66,154	4.0%
Total Net Variable Power Cost	11,755,152	10,941,536	813,617	7.4%

COST COMPONENT ($000)	N	Reference A	Difference (N - A)	Percent Difference
Real Levelized Fixed Cost	1,537,085	2,432,635	(895,549)	(36.8%)
TOTAL PVRR	13,292,238	13,374,170	(81,933)	(0.6%)

System resource utilization trends for the two all-gas portfolios are in line with a coal versus gas resource comparison as well. Existing coal and gas resources are utilized more heavily for both all-gas portfolios, with Portfolio N having slightly higher utilization than Portfolio M. Figures 8.6 and 8.7 show for portfolios M and N the utilization trends for existing resources in comparison to Portfolio A.

Figure 8.6 – Utilization Trends for Existing Resources: Portfolio A vs. Portfolios M

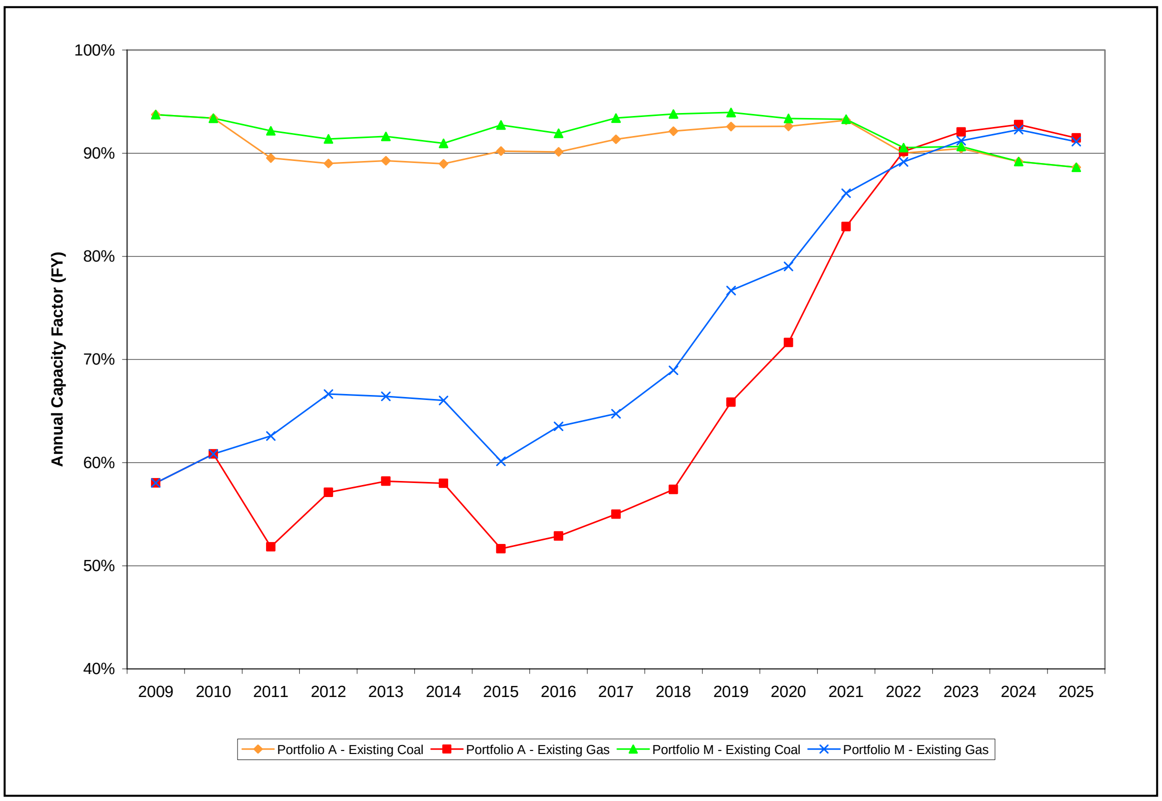
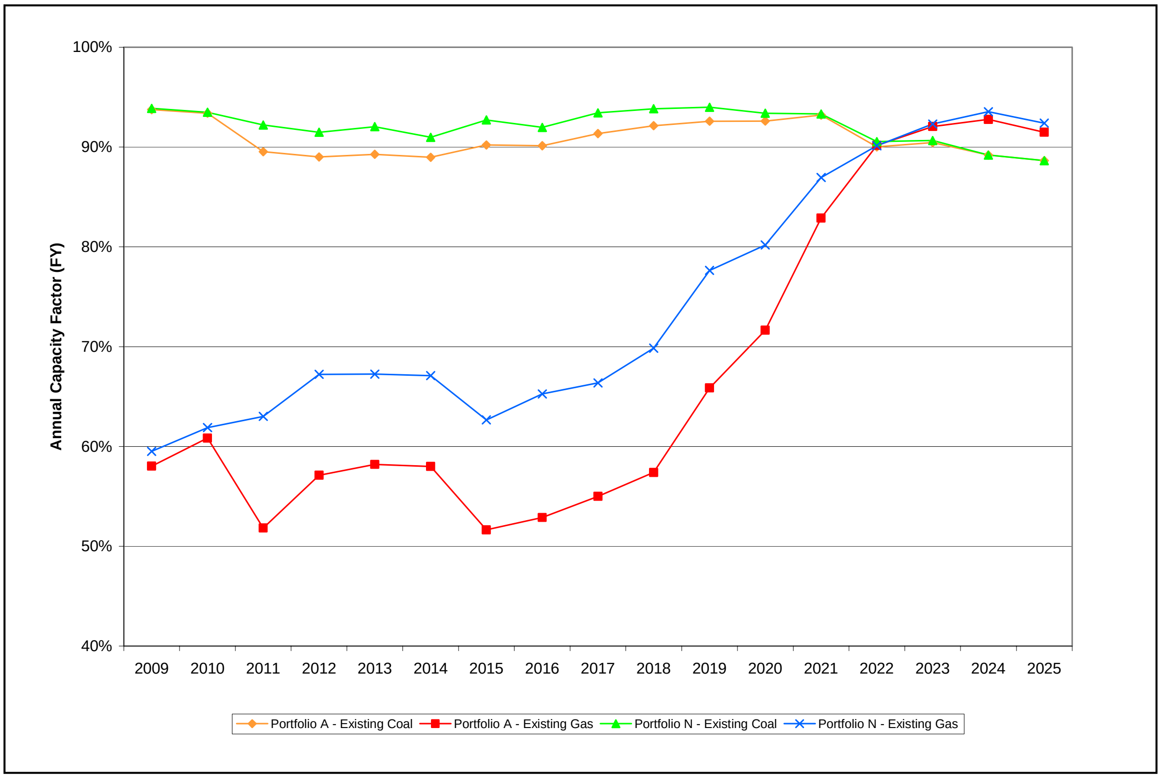


Figure 8.7 – Utilization Trends for Existing Resources: Portfolio A vs. Portfolios N



The east-to-west transfers for both Portfolios M and N are lower than those for Portfolio A until FY 2015, after which they are higher. The lack of the FY 2015 Wyoming coal resource combined with the east-side gas resources added in FY 2014 and FY 2015, explain the relatively higher transfers for Portfolios M and N.

Portfolio M's west-to-east transfers remain relatively stable during the study period, fluctuating around the 50 MWa level. From FY 2015 and onward, transfers are well below those for Portfolio A due to Portfolio M's lack of the FY 2015 west-side Wyoming coal resource. Portfolio N's west-to-east transfers exhibit a similar pattern, and remain well below Portfolio A's transfers beginning in FY 2015.

IGCC-Intensive Portfolio

Portfolio O includes two IGCC proxy resources; the original IGCC plant in Wyoming and one that substitutes for the brownfield pulverized coal unit in Utah. The total IGCC capacity is 736 MW for this portfolio. As expected, this portfolio does poorly relative to the others on a PVRR basis. Only Portfolios I and Q (hydro pumped storage and the second transmission expansion portfolios) have a higher PVRR. Table 8.17 shows the PVRR cost components for Portfolios O and A.

Table 8.17 – Portfolio PVRR Cost Components: Portfolio O vs. Portfolio A

COST COMPONENT ($000)	O	Reference A	Difference (O - A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,846,478	10,568,841	277,636	2.6%
Total Variable O&M Cost	1,069,656	1,021,323	48,333	4.7%
Total Emissions Cost	(563,246)	(459,986)	(103,260)	22.4%
Total Start-up Cost	10,653	11,014	(361)	(3.3%)
Variable Contract Cost	1,815,281	1,798,135	17,146	1.0%
Sales	(3,619,579)	(3,663,728)	44,149	(1.2%)
Purchases	1,762,138	1,665,937	96,202	5.8%
Total Net Variable Power Cost	11,321,381	10,941,536	379,845	3.5%
Real Levelized Fixed Cost	2,193,923	2,432,635	(238,712)	(9.8%)
TOTAL PVRR	13,515,303	13,374,170	141,133	1.1%

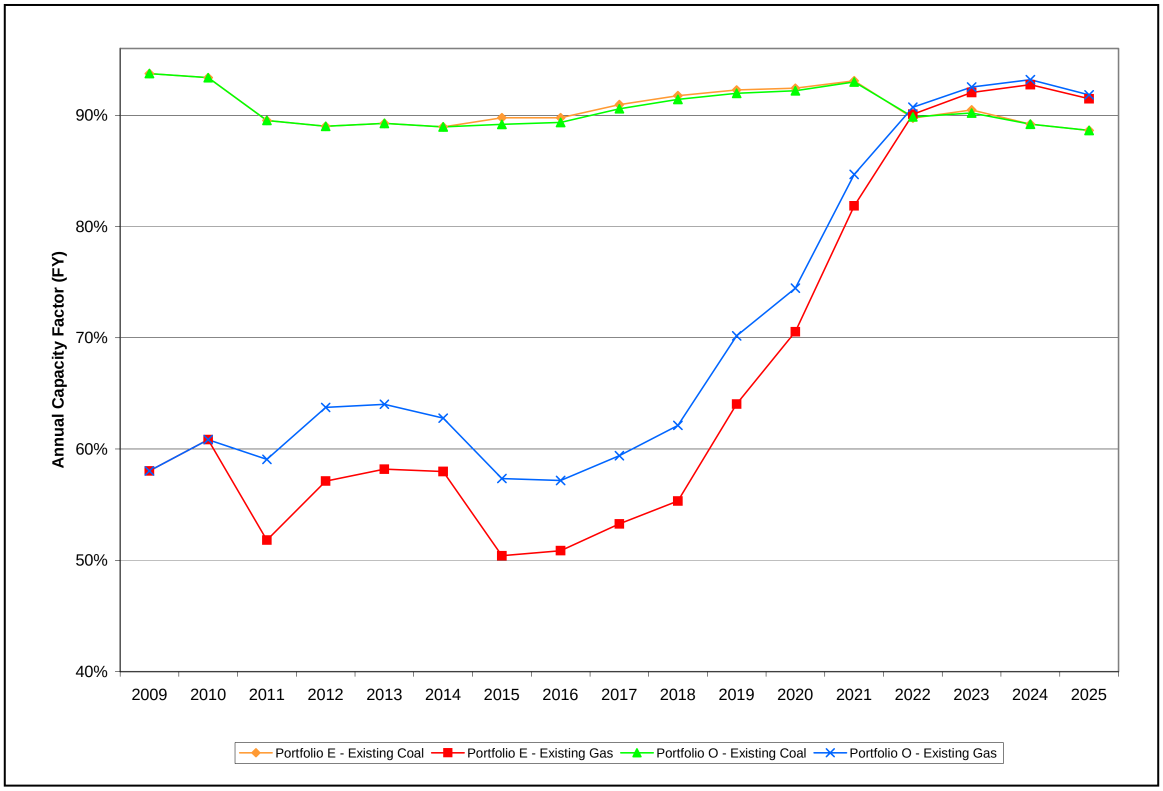
The IGCC resources have a relative variable cost advantage over Portfolio E’s Wyoming pulverized coal resource on a per-MWh basis, as shown in Table 8.18 below.

Table 8.18 – Variable Cost Comparison, Wyoming Pulverized Coal vs. IGCC

Unit	Average Annual Variable Costs ($/MWh), FY 2014-2025		
	Fuel	Variable O&M	Total Variable
Wyoming Pulverized Coal (from Portfolio E)	15.29	1.18	16.47
Utah IGCC Unit (from Portfolio O)	11.21	2.67	13.88
Wyoming IGCC Unit (from Portfolio O)	13.78	2.71	16.48

However, the IGCC units’ higher assumed outage rates increase gas unit utilization and requires more spot market purchases, thereby increasing Portfolio O’s total net variable cost. This utilization impact is evident in Figure 8.8, which shows for Portfolios O and E the capacity factor trends for existing resources. (Portfolio E is used for the comparison since it doesn’t include an IGCC resource.)

Figure 8.8 – Resource Utilization Trends: Portfolio O vs. Portfolio E



Capacity Expansion Model Portfolio

As discussed in Chapter 7, this portfolio was constructed from a solution of the Capacity Expansion Model (CEM). In addition to supporting the CEM validation effort, this portfolio also tests the substitution of the FY 2014 Wyoming pulverized coal resource with a CCCT.

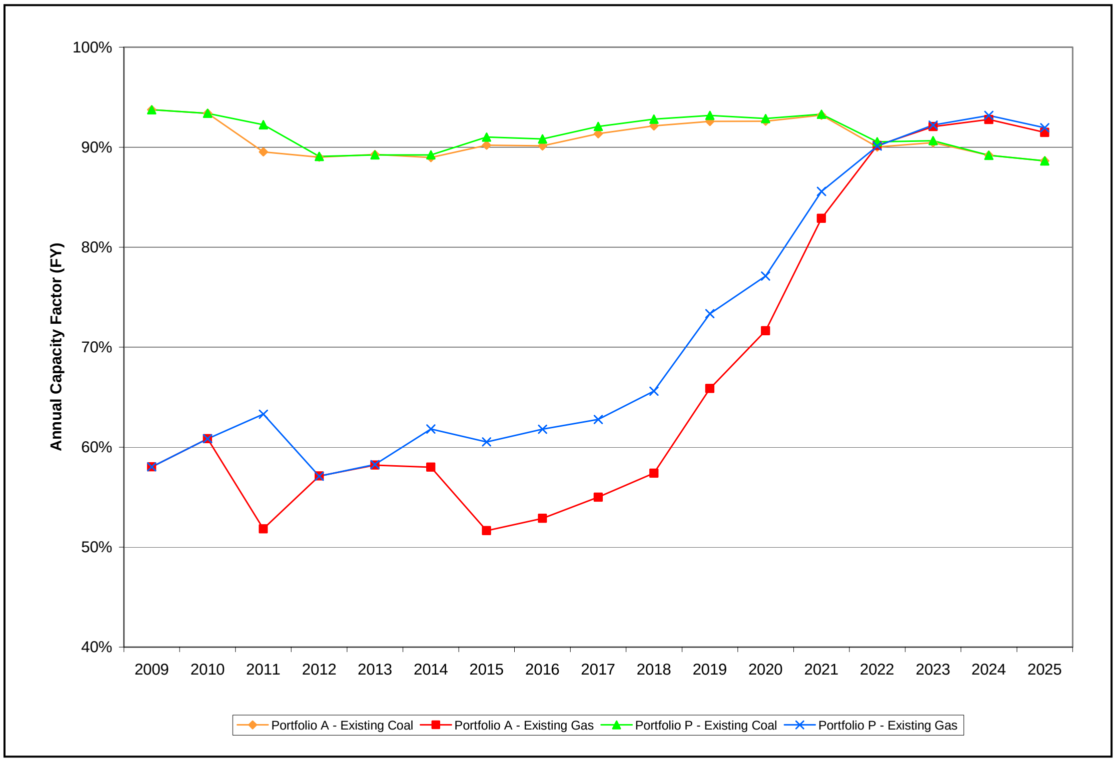
Portfolio P performed well, coming in second among all candidate portfolios with a PVRR of $13.26 billion, and $117 million less than Portfolio A's PVRR. Table 8.19 shows the PVRR cost components for Portfolios P and A. Portfolio P's PVRR reflects the characteristic tradeoff between low capital cost and high variable cost for gas resources. It also reflects the characteristic increase in spot market purchases relative to less gas-intensive portfolios. Resource utilization by portfolio, for existing resources, is shown in Figure 8.9.

Table 8.19 – Portfolio PVRR Cost Components: Portfolio P vs. Portfolio A

COST COMPONENT ($000)	P	Reference A	Difference (P - A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,743,572	10,568,841	174,730	1.7%
Total Variable O&M Cost	1,027,200	1,021,323	5,877	0.6%
Total Emissions Cost	(518,548)	(459,986)	(58,762)	12.8%
Total Start-up Cost	11,000	11,014	(14)	(0.1%)
Variable Contract Cost	1,813,345	1,798,135	15,210	0.8%

COST COMPONENT ($000)	P	Reference A	Difference (P - A)	Percent Difference
Sales	(3,607,329)	(3,663,728)	56,399	(1.5%)
Purchases	1,821,383	1,665,937	155,447	9.3%
Total Net Variable Power Cost	11,290,423	10,941,536	348,887	3.2%
Real Levelized Fixed Cost	1,966,965	2,432,635	(465,670)	(19.1%)
TOTAL PVRR	13,257,388	13,374,170	(116,782)	(0.9%)

Figure 8.9 – Resource Utilization Trends: Portfolio P vs. Portfolio A



Transmission Expansion/Additional Wyoming Coal Portfolio

Portfolio Q includes two FY 2014 pulverized coal units in Wyoming (958 MW, 83 percent PacifiCorp ownership share), along with the development of two new PacifiCorp-owned 345 kV transmission lines to transport the power to northern Utah. This portfolio also includes the FY 2009 Utah wet cool CCCT and FY 2011 Utah pulverized coal resources.

Portfolio Q has the highest PVRR of all the candidate portfolios, at $13.584 billion. This PVRR is about $210 million, or 1.6 percent, higher than Portfolio A's PVRR. Given the low production cost characteristics of pulverized coal plants, Portfolio Q results in the lowest net variable power cost of all candidate portfolios at $10.573 billion. In contrast, Portfolio Q has the highest fixed cost of all candidate portfolios as well, at $3.01 billion. This cost is nearly $1.5 billion higher than the portfolio with the lowest fixed cost, Portfolio N. Table 8.20 shows the PVRR cost components for Portfolios Q and A.

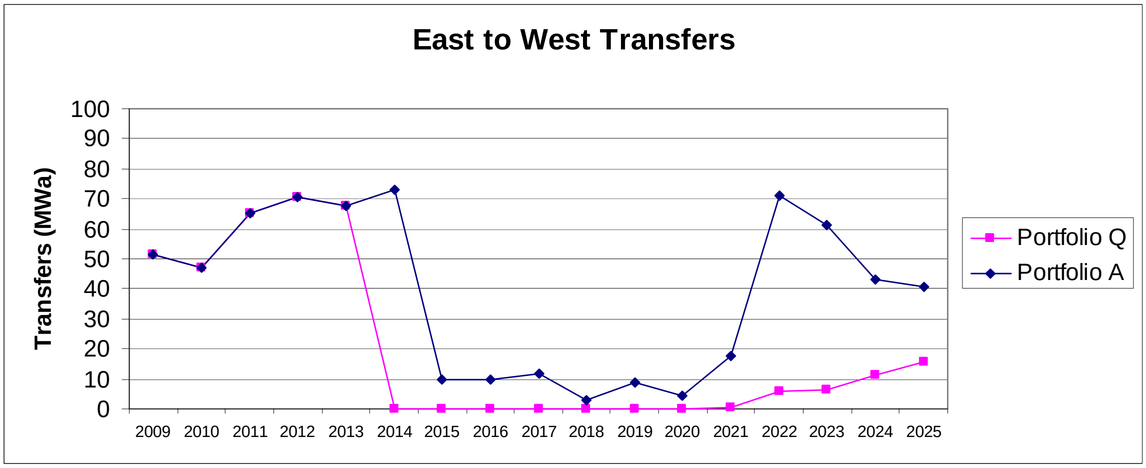
Table 8.20 – Portfolio PVRR Cost Components: Portfolio Q vs. Portfolio A

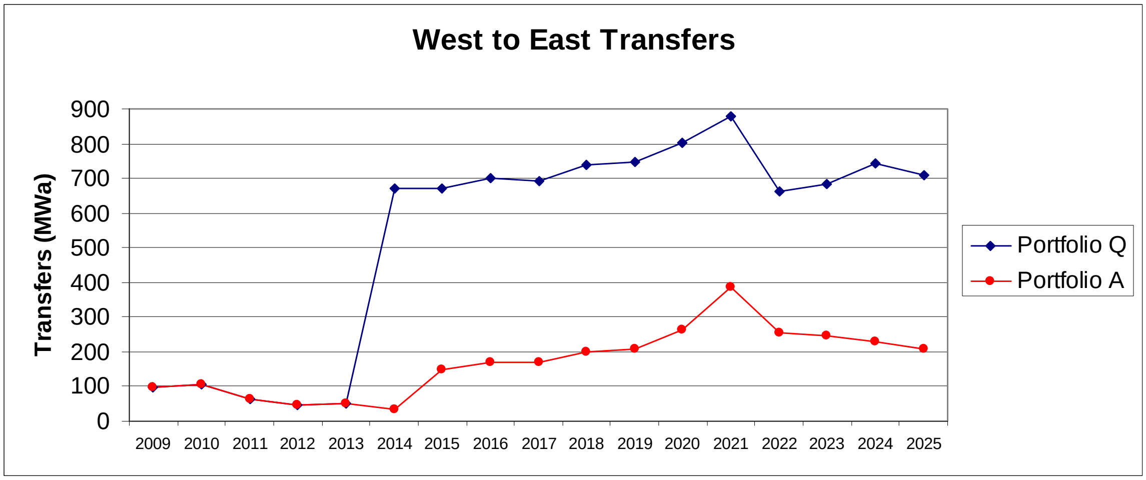
COST COMPONENT ($000)	Q	Reference A	Difference (Q - A)	Percent Difference
Variable Costs				
Total Fuel Cost	10,079,224	10,568,841	(489,617)	(4.6%)
Total Variable O&M Cost	951,416	1,021,323	(69,907)	(6.8%)
Total Emissions Cost	(321,873)	(459,986)	138,113	(30.0%)
Total Start-up Cost	11,641	11,014	627	5.7%
Variable Contract Cost	1,764,416	1,798,135	(33,720)	(1.9%)
Sales	(3,527,330)	(3,663,728)	136,398	(3.7%)
Purchases	1,615,374	1,665,937	(50,563)	(3.0%)
Total Net Variable Power Cost	10,572,867	10,941,536	(368,668)	(3.4%)
Real Levelized Fixed Cost	3,011,653	2,432,635	579,019	23.8%
TOTAL PVRR	13,584,520	13,374,170	210,350	1.6%

Concerning spot market activity, Portfolio Q's lower purchases relative to those of Portfolio A is consistent with the operating cost benefits associated with Portfolio Q's greater coal generation. However, Portfolio Q's market sales are also lower than those for Portfolio A, which appears to be counterintuitive. An examination of Portfolio Q's east-side plant utilization trends beginning in FY 2014 (when the 958 MW of Wyoming coal comes on line) indicates that the new coal plants initially drive down utilization of many other units by a significant degree, followed by gradual recovery if these units due to increasing load. Portfolio Q capacity factors for coal plants in FY 2014 are, on average, 6 percentage points lower than those for Portfolio A. A similar effect can be seen with respect to certain gas unit capacity factors. In summary, the new Wyoming coal plants displace generation from existing higher-cost resources in the east, and reduce spot market sales opportunities relative to Portfolio A.

Figure 8.10 shows the control area transfer trends for Portfolios Q and A. The impact of Portfolio A's additional FY 2014 Wyoming coal addition is evident. (Note that the Bridger proxy resources are modeled as a west-side addition.) In contrast, the west-to-east transfers jump from 49 MWa in FY 2013 to 669 MWa in FY 2014, exceeding Portfolio A's transfers by 635 MWa.

Figure 8.10 – Control Area Transfer Trends: Portfolio Q vs. Portfolio A





Summary Performance for Candidate Portfolios

Figure 8.11 presents the ranked PVRRs for each of the portfolios evaluated. The portfolio group designated as "Risk Analysis Portfolios" meets the criteria of (1) having the lowest PVRRs of all portfolios examined (with the exception of Portfolio Q), and (2) reflecting portfolio characteristics of interest for the risk analysis phase of the modeling process. Specifically, these characteristics include: various mixtures of coal and gas proxy resources (Portfolios E, K and P); deferred or minimal coal unit construction (Portfolios L and J), an "all gas" resource composition distinguished by a different gas technology mix (Portfolios M and N), and; a transmission expansion scenario (Portfolio Q).

To provide a rigorous risk analysis and keep the set of portfolios to a manageable size[17], certain portfolios were eliminated from the risk analysis group in accordance with the selection criteria above. For example, IGCC and pulverized coal technologies have effectively identical fuel price volatility risks. Including the IGCC portfolios in the risk analysis group is therefore not necessary given that the pulverized coal portfolios adequately represent the risk profile for the baseload coal resources examined for this IRP. In summary, the selected risk analysis portfolios adequately capture the quantifiable risks associated with the various proxy resource combinations evaluated.

Major observations concerning summary cost performance of the candidate portfolios include the following:

- Portfolios M and P have the lowest PVRRs at $13.256 million and $13.258 million, respectively; their PVRRs are effectively equivalent.
- PVRR variability across all portfolios is small, largely reflecting the strategy of incrementally modifying the Reference Portfolio to analyze a single resource change. The standard deviation for the 16 portfolio’s PVRRs is only about $107 million.
- The difference between the highest and lowest PVRRs is $329 million, or about 2.5 percent of the average PVRR for the 17 portfolios ($13.28 billion).

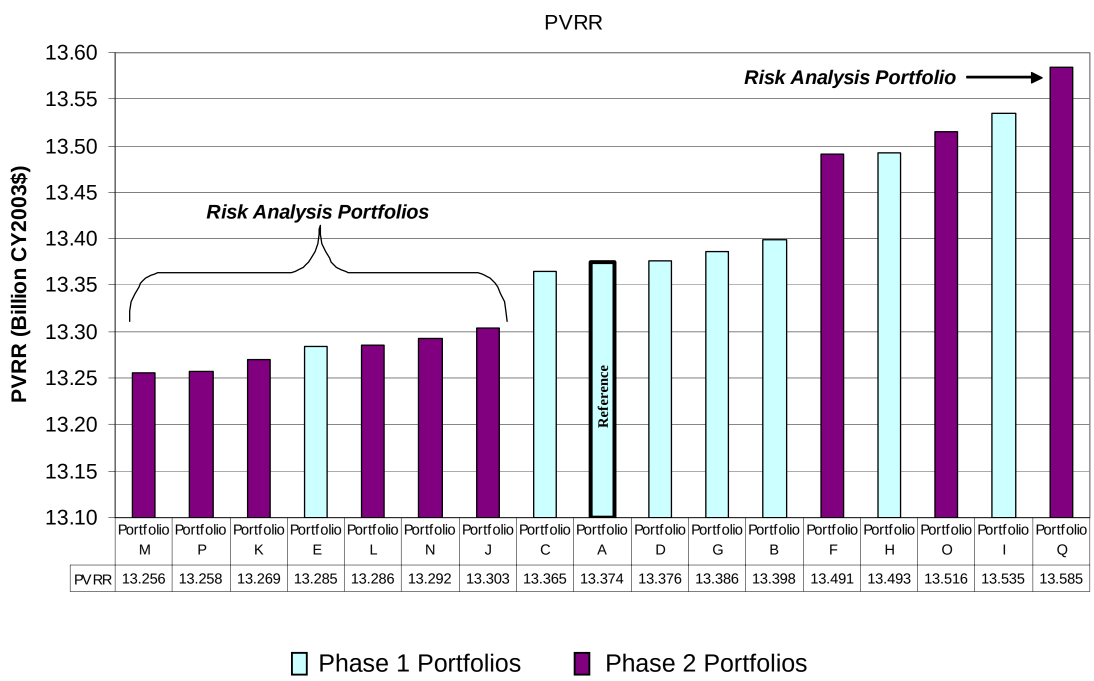
For the portfolios selected for risk analysis—M, P, K, E, L, N, J, and Q—major observations include the following:

- The PVRR range for the low and high PVRR portfolios in the risk analysis group is about $48 million. The average is about $13.28 billion.
- Portfolios with a high or complete reliance on new gas resources dominate the group. Four of these seven portfolios (including the top two, M and P) have gas units contributing at least 80 percent of the total installed new capacity.
- The most significant difference between the risk analysis portfolio group and the others is the absence of an IGCC unit in the resource mix. As mentioned above, the cost impact of including IGCC resources in a portfolio was to increase PVRR by an average of $92.5 million.
- Although fixed costs contribute much less to total PVRR than variable costs, relative fixed cost differences have about an equal impact on PVRR rankings as differences in variable costs.

For reference purposes, model run output for each portfolio is summarized in a Portfolio Scorecard. The Scorecard includes PVRR and capital costs, emissions, market sales and purchases for FY 2015, capacity factors by unit type for FY 2015, and control area transfers (FY 2008, 2010, and 2015). The complete Scorecard for all portfolios tested is included as Appendix E, “Portfolio Scorecard and Emission Costs.” This Appendix also contains a table of per-MWh emission costs for FY 2015 by resource type. The costs are listed for a set of portfolios that represent the resource technologies evaluated.

[17] A practical consideration for selecting portfolios for risk analysis was the lengthy stochastic simulation run-times (at least 30 hours per run) and the extent of data processing associated with stochastic and associated statistical analysis. For example, 22 risk measurement tests were computed for each portfolio included in the stochastic simulations. A number of pair-wise statistical comparison tests involving the ten risk analysis portfolios were also conducted, requiring the computation of 45 test statistics for each pair-wise comparison test.

Figure 8.11 – Candidate Portfolio PVRR Rankings



<u>Portfolio Names</u>

A. Reference:
- **(East) PC in Utah – FY2011**
- **(East) Dry Cooling Combined Cycle Combustion Turbine (DC-CCCT) – FY2009**
- **(East) Wet Cooling Combined Cycle Combustion Turbine (WC-CCCT) – FY2014**
- **(East) Integrated Gasification Combined Cycle (IGCC) – FY2015**
- **(West) DC-CCCT – FY2013**
- **(West) IC Aeroderivative Single Cycle Combustion Turbine (IC Aero SCCT) - FY2013**

B. Remove FY2011 Utah Pulverized Coal, Replace with DC-CCCT
C. Replace FY2009 CCCT with Aeros
D. Defer FY2011 Utah Pulverized Coal, Replace with WC-CCCT
E. Replace FY2015 IGCC with WY Pulverized Coal
F. Transmission Expansion
G. Build on East Side vs. West Side
H. Replace FY2014 CCCT with Compressed Air Energy Storage
I. Replace FY2014 CCCT with Hydro Pumped Storage
J. Portfolio B, with Wyoming Pulverized Coal Replacing IGCC
K. Portfolio C, with Wyoming Pulverized Coal Replacing IGCC
L. Portfolio D, with Wyoming Pulverized Coal Replacing IGCC
M. All Gas with CCCTs
N. All Gas with CCCTs and IC Aero SCCTs
O. Utah and Wyoming IGCC
P. CEM-selected Portfolio
Q. Transmission Expansion with Additional Wyoming Pulverized Coal

RISK EVALUATION RESULTS

Stochastic Risk Simulations

Expressing each portfolio in terms of deterministic PVRR conveys just one dimension of portfolio performance. The risk of each portfolio represents another key dimension. Risk measures are created for two types of stochastic runs as defined in Chapter 4, one in which all stochastic parameters vary or the 'All-In' analysis, and another in which just power and gas prices, along with forced outages vary, herein called the "Spark Spread" analysis. The 'All-In' stochastic analysis is performed on Portfolios N, M, J, P, L, K, E, Q, 12% PM, and 18% PM. The spark spread stochastic analysis is performed on all these portfolios with the exception of the 12% PM and the 18% PM portfolios.

To ensure that the stochastic results are supported by a rigorous statistical analysis, PacifiCorp also calculated tests to determine statistically significant differences between portfolio risk measurement results. These statistical results are reported along with the stochastic analysis results. Since stochastic analysis implies random outcomes, a statistical analysis of the results is reasonable, if not necessary.

The risk measures used in the stochastic analysis can be divided into three categories: average risk, risk exposure, and risk/cost trade-off. Average risk considers measurements that express the average amount of PVRR risk comparing one portfolio against another when the inputs are stochastically varied. Risk exposure measures the possible extreme value of PVRR, or the potential amount of risk in each portfolio. The risk/cost trade-off measures illustrate the amount of potential risk with the cost of each portfolio.

A listing of the risk analyses follows:

- Average risk
  - Average of 100 iterations for Stochastic Total Costs
  - Standard deviation of 100 iterations for Stochastic Total costs
  - Statistical tests of the mean and variance of the stochastic costs for the 100 iterations
  - Difference between the deterministic and stochastic average total cost compared with the stochastic average total costs.
  - Statistical Tests of the differences between the deterministic and stochastic average total costs.
- Risk exposure
  - Upper tail average of the stochastic average total cost
  - Statistical tests for the upper tail values.
  - Difference between the deterministic and stochastic average total cost compared with the upper tail stochastic average total costs.
- Risk/cost trade-off
  - Stochastic average total costs compared against the average of the upper tail of stochastic total costs

– Stochastic average total cost compared against the standard deviation of the stochastic total cost.

Each measure provides a different perspective on the risk profile of the final portfolios. Taken in aggregate, the measures assist in distinguishing between portfolios.

The risk evaluation process in this section should be considered as progressive analysis. That is, the analysis of average risk measures the expected, or average, risk level for each portfolio; the analysis of risk exposure measures the extreme risk level for each portfolio; and the analysis of risk/cost trade-off measures the risk/cost combination for each portfolio.

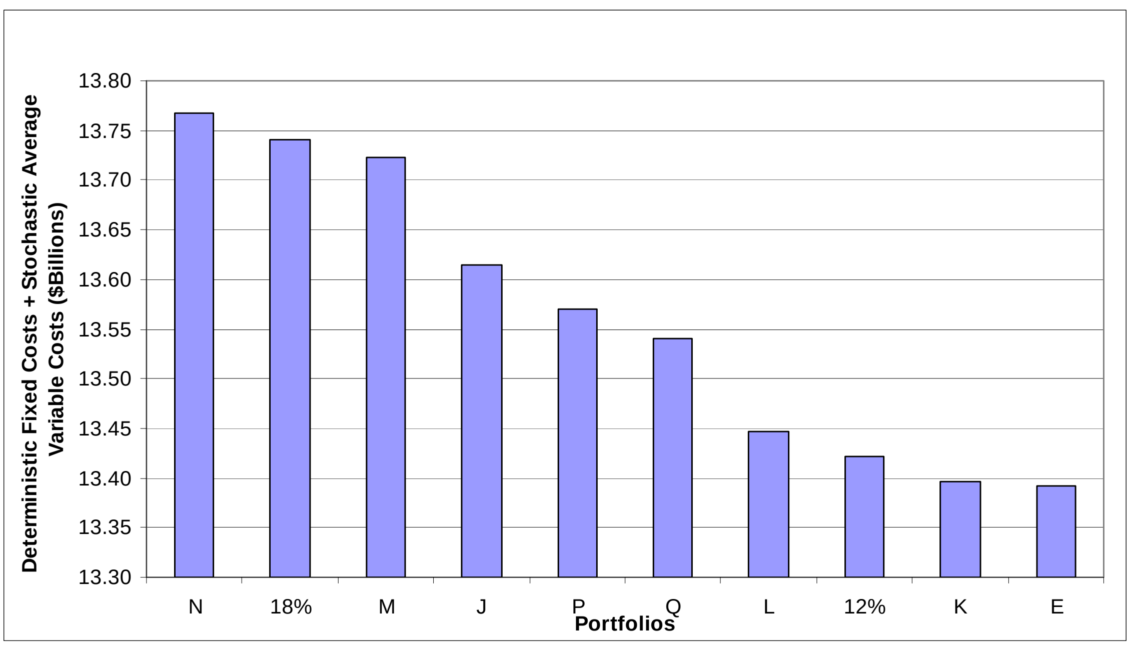
Risk Measures for 'All-In' Stochastic Runs

Average Risk

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

Figure 8.12 illustrates the total average costs for the 100 iterations for the 'All-In' analysis. The average over 100 iterations shows the expected value of total operating costs based on stochastic inputs. Figure 8.12 indicates that the lower stochastic total cost portfolios are E, K, L, and 12% PM. These portfolios tend to have more resource-type balance with respect to the generation from additional capacity. Two of the higher total cost portfolios are M and N. These portfolios tend to have a higher concentration of additional gas units.

Figure 8.12 – Average Fixed Deterministic and Stochastic Variable Costs: 'All-In' Basis



Confidence intervals can be constructed around the stochastic average total costs as a measurement of risk. A confidence interval is an interval constructed from the PVRRs of the 100 iterations. It is assumed that the mean of the iterations have a normal distribution[18]. The following equation gives the confidence bounds:

$$\bar{x} \pm 1.645 s / \sqrt{n}$$

where $\bar{x}$ is the average stochastic total cost, s is the standard deviation of the 100 total costs iterations, and n is the number of iterations.

Inferences can be made from these confidence intervals. If the confidence intervals from two portfolios overlap, then the portfolios are not statistically different. If the portfolios do not overlap, then there is a significant difference. It was found with the confidence interval analysis that all of the 10 portfolios overlapped and did not exhibit any statistical difference.

The confidence interval analysis assumes that there is no dependence between portfolios. When the stochastic models are run in MARKETSYM, the same seeds have to be implemented for each stochasticized variable across portfolios. The same seeds across portfolios cause a dependence, or strong correlation, between all of the portfolios. When there is dependence between populations, then the correct test to detect a difference between the means of portfolio PVRRs is the paired-difference test[19,20]. That is, since iteration one has the same characteristics across portfolios, each portfolio is linked by an underlying common characteristic. A similar linkage exists for all iterations in the stochastic analysis causing dependence across portfolios. Implementing the paired-difference test for each pair of portfolios leads to the results illustrated in Figure 8.13.

[18] The average of any set of numbers tends toward a normal distribution if the number of iterations is sufficiently large. In most statistical studies it is assumed that if the number of iterations is greater than 30, then the average is normally distributed due to the Central Limit Theorem.

[19] Statistics for Management and Economics, 3rd Ed., William Mendenhall and James E. Reinmuth, 1978, pp. 293-7.

[20] The null hypothesis for the paired-difference test is H_0: $\mu_d = 0$ where μ_d is the mean of the differences between two populations. The null hypothesis is saying that there is no difference between the stochastic average PVRR between two portfolios. The test statistic is $\dfrac{\bar{d}}{(s_d / \sqrt{n})}$ where $\bar{d}$ is the sample mean of the differences between two portfolio PVRRs over the 100 iterations, s_d is the standard deviation of the difference between two portfolio PVRRs over the 100 iterations, and n is the number of iterations, i.e., 100. Significantly high or low values of the test statistic would tend to imply that the null hypothesis is not true.

Figure 8.13 – Paired-Difference Results for the 'All-In' Case

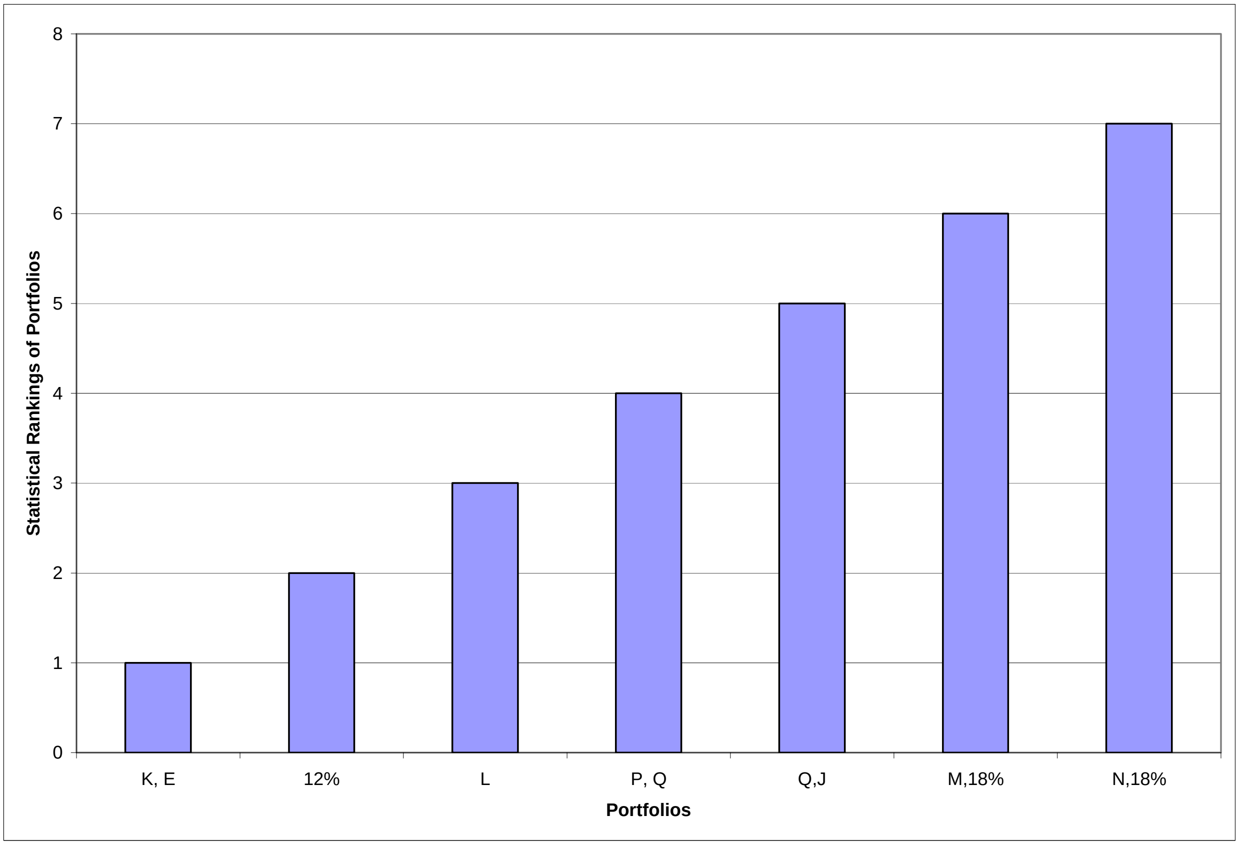
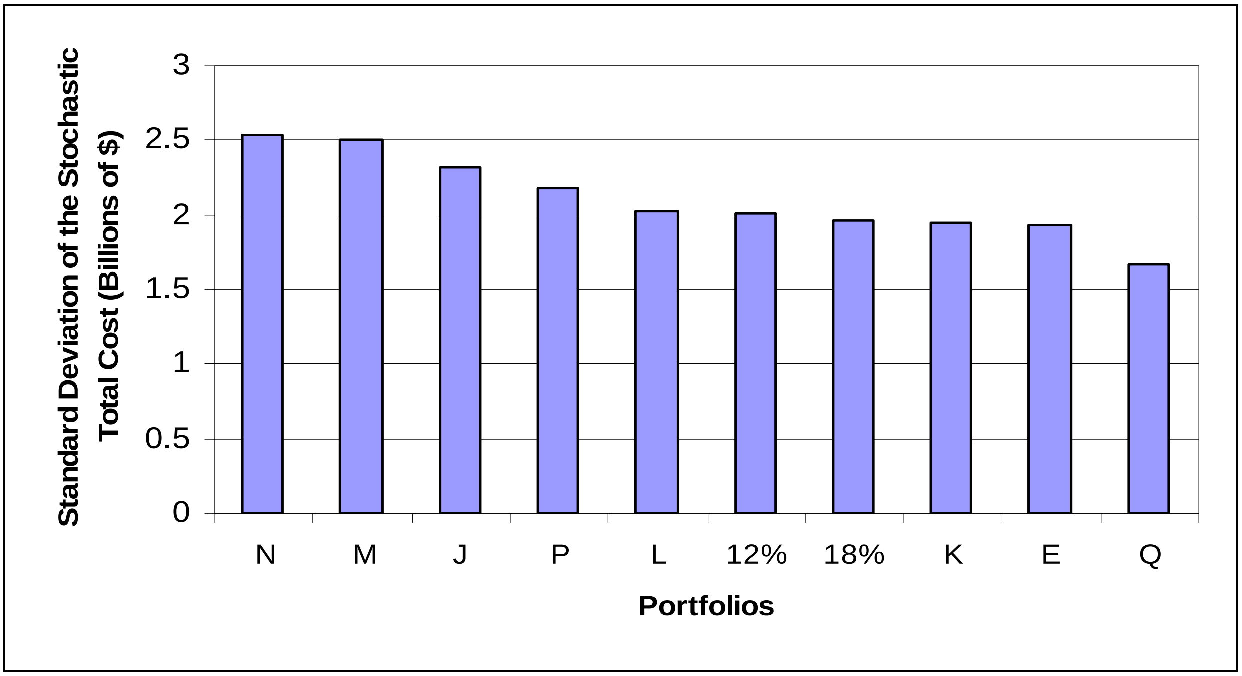


Figure 8.13 illustrates the statistical groupings of the means of the stochastic total costs for the portfolios, and how each statistical grouping ranks in total stochastic costs. The vertical axis reflects the rank of portfolios with respect to the average total stochastic cost. For example, the graph indicates that there is no statistical difference between the average total stochastic costs of Portfolios K and E, and that the average total stochastic cost for K and E is lower than all of the other portfolios. Since Portfolios K and E are in the group having the lowest average total stochastic cost, they have the lowest rank or a value of "1" on the vertical axis. Further, the graph indicates that the 12% PM portfolio has a stochastic mean total cost greater than that for portfolios K and E but less than the average stochastic total cost of the portfolios to the right of 12% on the horizontal axis. Since the 12% PM portfolio is in the group having the second lowest average total stochastic cost, it has the second lowest rank or a value of "2" on the vertical axis. The same reasoning can be applied to the other portfolios and their placement on the horizontal axis. For example, Portfolios N and 18% PM have statistically equal average total costs that are higher than all other portfolios. There is also "overlap" with some of the portfolios. For example, Portfolio Q is grouped with Portfolio P and Portfolio Q is also grouped with Portfolio J. These groupings imply that Portfolio Q is statistically the same as Portfolio P and it is also statistically the same as Portfolio J, but Portfolio P is not statistically the same as Portfolio J. The same reasoning can be applied to Portfolios M, N and 18% PM.

The conclusion from Figure 8.13 is that portfolios having a mixture of proxy resource types tend to have statistically lower average total cost than those which have relatively more proxy gas resources and generation. The exception to this rule is Portfolio Q, which tends to have higher capital and transmission costs.

The standard deviation of each portfolio for the 100 iterations is also a measure of average risk. Figure 8.14 illustrates the standard deviation for each portfolio over the 100 iterations.

Figure 8.14 – Standard Deviations for the 'All-In' Case



From Figure 8.14 Portfolio Q has the lowest standard deviation followed by Portfolios K and E. Portfolios M and N have the highest standard deviation. To further analyze the standard deviation notice that the variance is the square of the standard deviation. Once the variances are calculated, statistical differences between variances of the portfolios can be discerned by using the traditional F-test for variances.[21] This test is an approximate test for the variances.[22] Figure 8.15 illustrates the relative rankings of the portfolios based on the test of the variances.

[21] The F-test has as the null hypothesis H_0: $\sigma_1^2 = \sigma_2^2$, where σ_1^2 is the variance of the PVRRs for portfolio 1 and σ_2^2 is the variance of the PVRRs for portfolio 2. The test statistic is $F = s_1^2/s_2^2$ where s_1^2 is the sample variance of the PVRRs for portfolio 1 over the 100 iterations and s_2^2 is the sample variance of the PVRRs for portfolio 2 over the 100 iterations. Usually s_1^2 is the largest of the two sample variances. Large values of the test statistic would tend to imply that the variance of Portfolio 1 is larger than the variance for Portfolio 2.

[22] The F test is only an approximate test because of the dependence between each of the portfolios as discussed earlier in this section.

Figure 8.15 – Variance Test Results for the 'All-In' Case

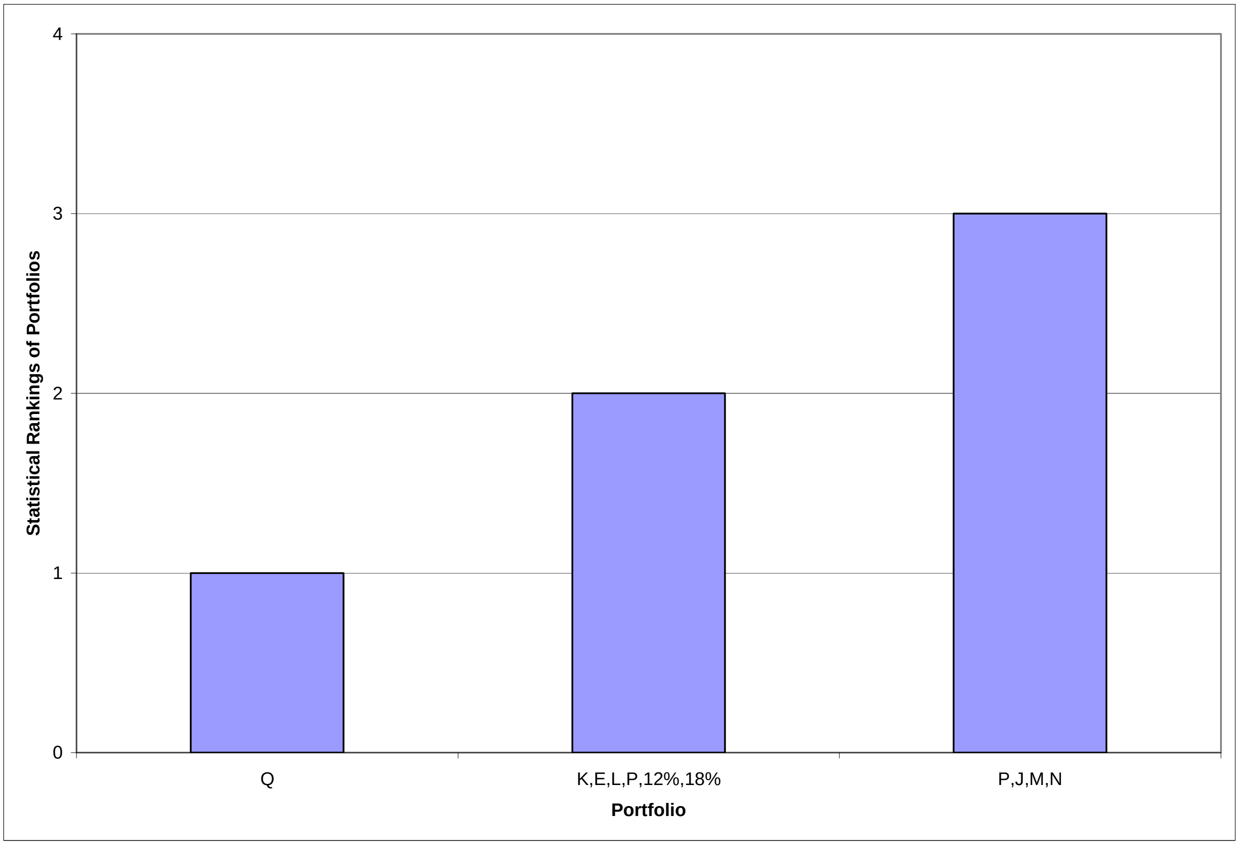


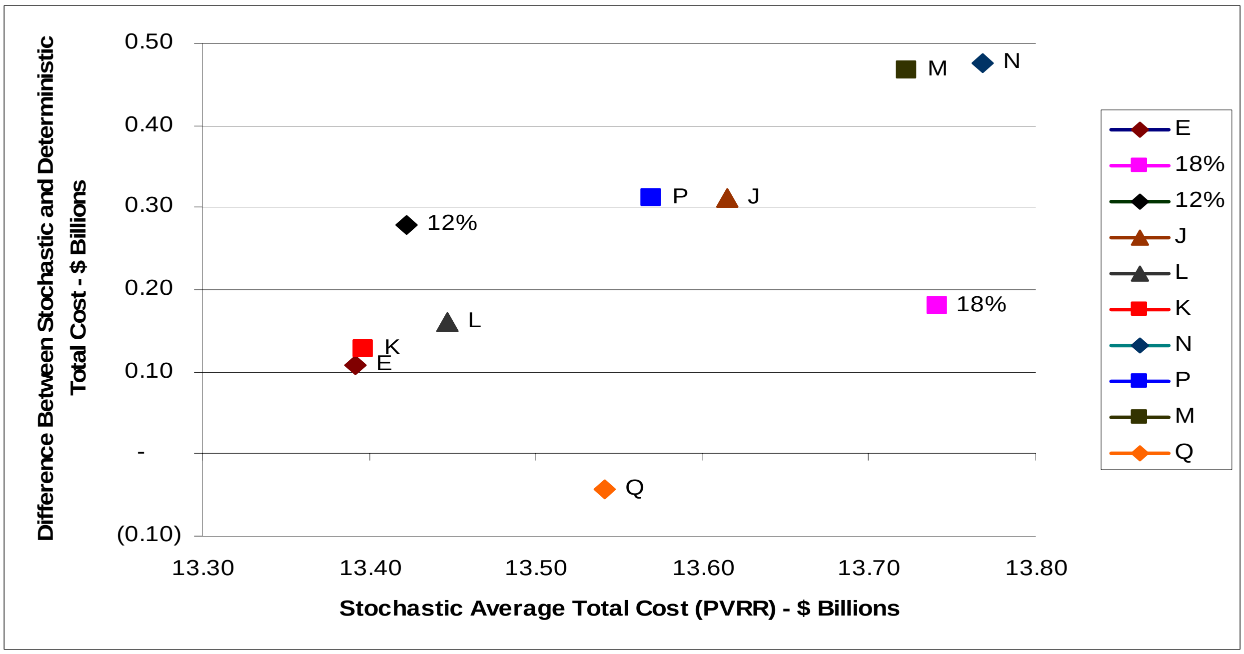
Figure 8.15 contains statistical rankings of portfolio variances similar to Figure 8.13. The graph indicates that Portfolio Q has the lowest variance/standard deviation among all of the portfolios and has a ranking of "1". Portfolio Q contains less new gas resources than the other portfolios, which means there is less generation subject to "shocked" gas prices. As a result, the variance for Portfolio Q should be lower. Further, Portfolios K, E, L, P, 12% PM, and 18% PM have statistically equal variances that are larger than the variance for Portfolio Q, hence the 2nd-place ranking. Portfolios P, J, M and N have statistically equal variances that are the largest variances among all portfolios.

The difference between the deterministic total cost and the stochastic total cost is also a measure of the average potential risk for a portfolio. This difference reflects how much costs could change on average due to stochastically varying the 'All-In' inputs. The difference between the stochastic average PVRR and deterministic PVRR is expected to be small, and in some cases negative.[23]

[23] The low or negative values indicate that the most economic use of market and gas generation is occurring. These portfolios have the lower values due to gas and market prices being lower than the cost of coal generation for iterations having low gas and electric market prices. So, cheaper gas generation and the market are displacing the coal generation which tends to decrease the average stochastic value when compared to the deterministic value. This point will be discussed further in the Spark Spread analysis section.

When the differences between the two total cost measures are compared with the stochastic average total cost, then a composite average risk measure can be considered. Figure 8.16 illustrates this composite average risk measure for each of the ten portfolios. The graph indicates that Portfolios Q, E, K, and L have among the lowest average risk as plotted on the x-axis, with Portfolio Q having the lowest measure of average risk as plotted on the y-axis. (See the footnote on the previous page, or the forthcoming Spark Spread analysis section, for an explanation of why Portfolio Q has a negative average risk measure value.) This result for Portfolio Q is indicative of it having the lowest amount of gas-fired capacity additions and subsequent gas-fired generation. The natural gas prices are a primary input that is varied during stochastic analysis. Since there are smaller amounts of this input being varied, the difference between the stochastic average and the deterministic PVRR should be lower. But, this portfolio has relatively higher stochastic average total costs due to the higher fixed and capital costs associated with additional coal generation units. Portfolios P and J have medium average risk, which is due to these portfolios having a relatively larger amount of additional gas proxy resources. Portfolios M and N have the highest amount of average risk, and are the portfolios with the most additional gas-fired capacity and generation.

Figure 8.16 – Composite Measure of Average Risk



Statistical tests which are similar to the paired-difference test can be performed on the difference between the average stochastic and deterministic costs. The results of these tests are shown in Figure 8.17.

Figure 8.17 – Test Summary: Difference between Stochastic & Deterministic Costs: 'All-In' Basis

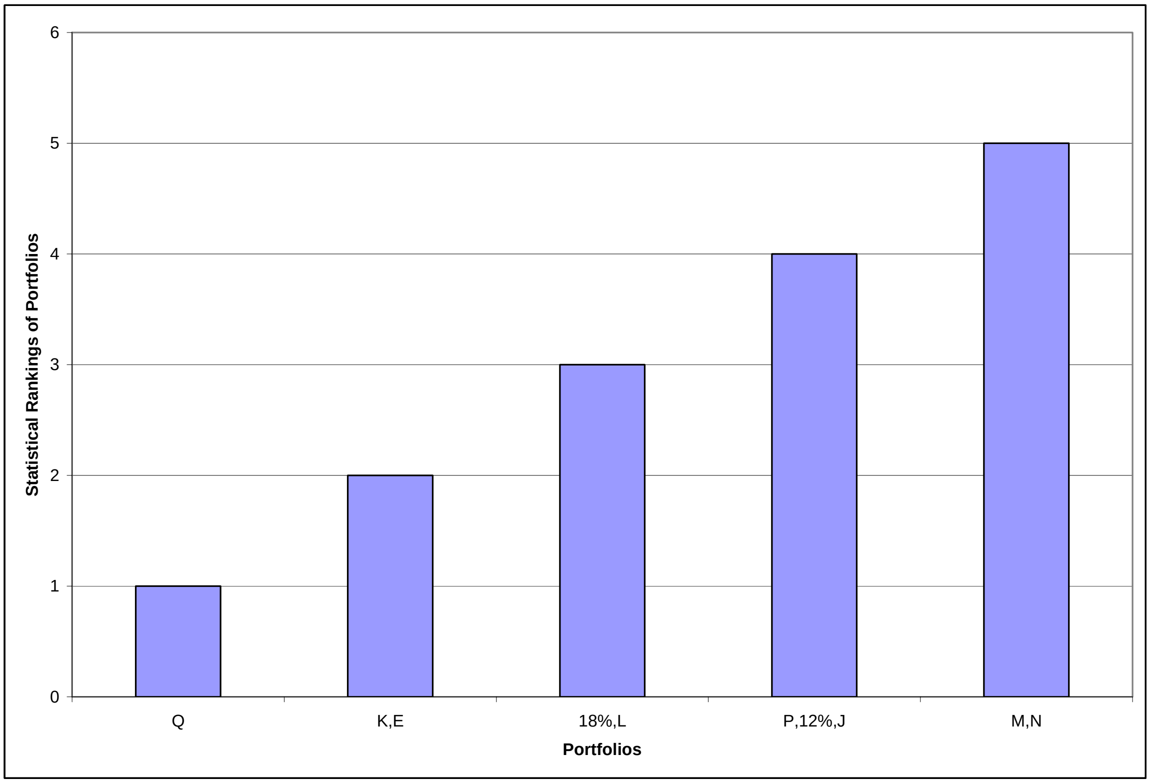


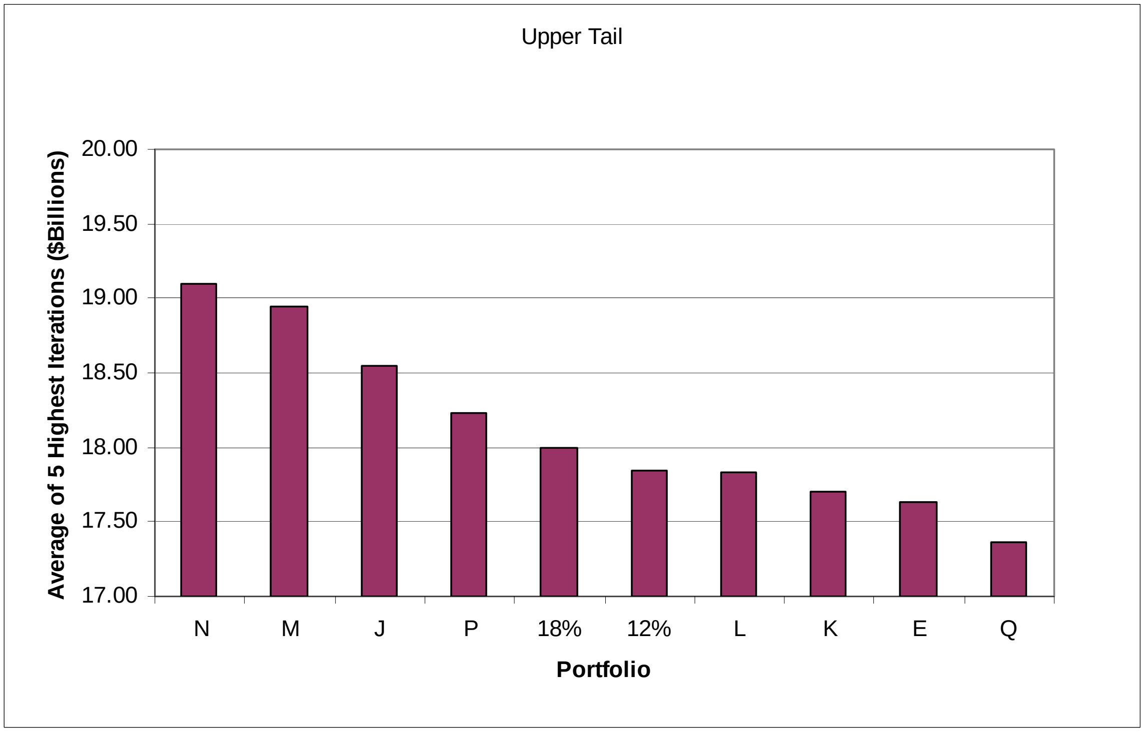
Figure 8.17 shows that portfolio Q has the least difference between average stochastic and deterministic costs. This result indicates that Q has the statistically lowest average risk. The next lowest portfolios are K and E. The highest average risk portfolios according to this measure are portfolios M and N. These results are similar to the previous results. That is, portfolio Q has the lowest cost ranking due to less additional gas, while portfolios M and N have the highest ranking due to their relatively higher reliance on additional gas units.

Risk Exposure

Since ratepayers are concerned with potential high-end risk exposure, the next set of measures show the average and the standard deviation of the five highest iterations of the stochastic costs. The larger this upper tail average, the more risk potential for the portfolio. The larger the standard deviation, the more variability there is around the upper tail average. If there is more variability around this average, then there is more potential risk exposure. These upper tail measures are not as robust as the stochastic average value, given that they are based on only five observations; however, they still can give an idea of the potential high-end costs of a particular portfolio.

Figure 8.18 shows the average of the upper tail, consisting of the five highest-PVRR iterations for each portfolio. The ordering of the upper tail averages remains relatively consistent with the ordering of the overall average. The portfolios with a mixture of planned resource types generally remain lowest cost (E, L, and K). The upper tail average for Portfolio Q is among the lowest due to the relatively low amounts of additional gas resources included in this portfolio. If there is a lesser amount of gas capacity in the portfolio, then this varied component of the stochastic analysis should be less than for other portfolios that have more gas capacity.

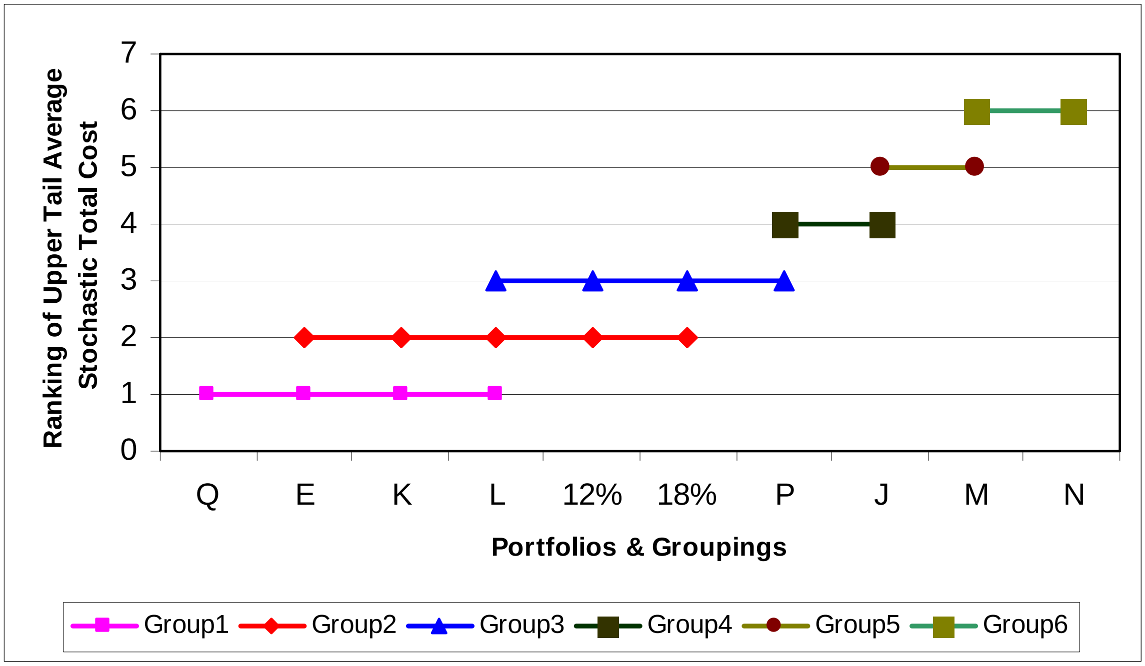
Figure 8.18 – Upper Tail Average Cost: 'All-In' Basis



Of all the portfolios, the 12% PM portfolio has the highest proportion of energy-not-served (ENS) contributing to total cost. Furthermore, the 12% planning margin has 25% higher ENS costs than the portfolio with the next highest amount of ENS. This higher ENS contribution is due to the fact that the 12% planning margin portfolio has the least amount of new supply. In the stochastic runs, ENS was valued at $750/MWh. This cost could be undervaluing the true or societal costs of ENS. Therefore, despite having a low total deterministic PVRR, the 12% planning margin portfolio is viewed as the most "risky" in terms of meeting PacifiCorp's system reliability objectives.

Statistical tests can be performed on the upper tail averages and the upper tail variances of the portfolios. The grouping and ranks of portfolios based on statistical tests on the averages for the selected portfolios are summarized in Figure 8.19.

Figure 8.19 – Upper Tail Test Summary for Averages: 'All-In' Basis



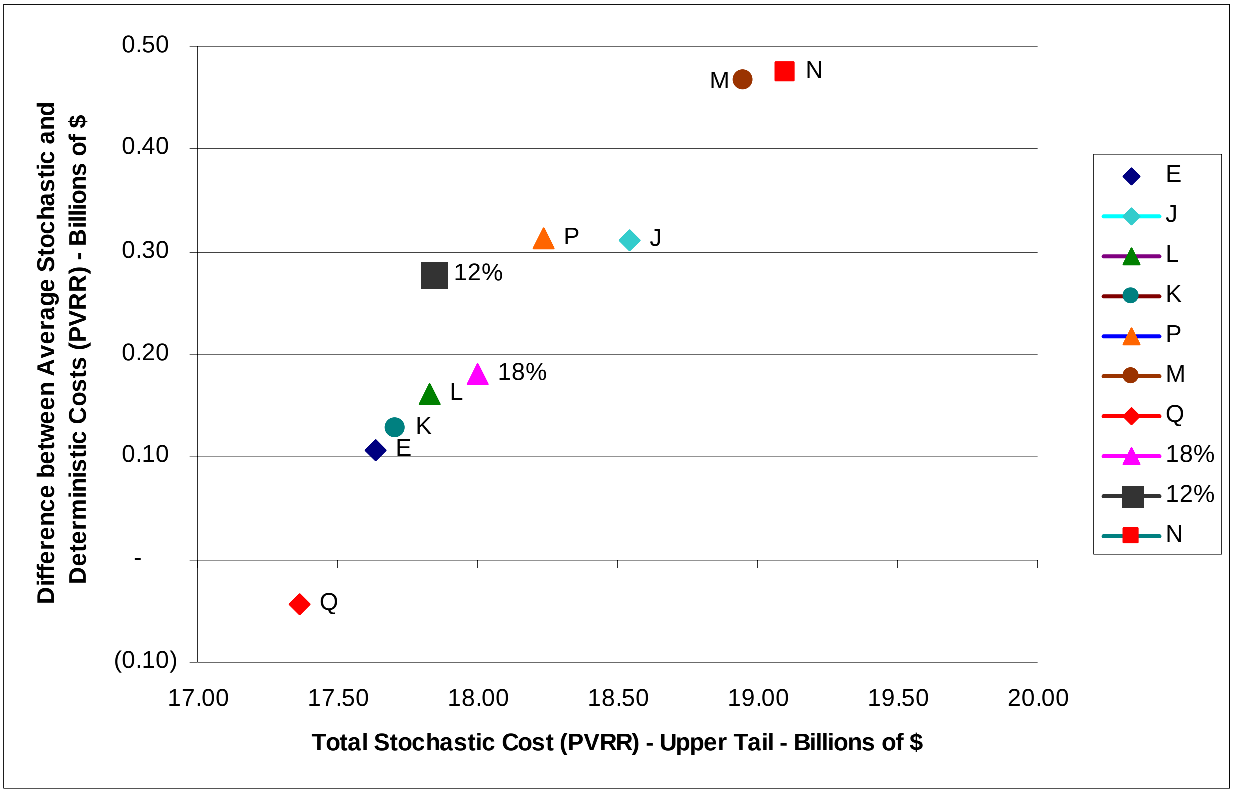
Since there are only five observations (iterations) considered in the upper tail analysis, the results in Figure 8.19 are not as distinct as for the previous statistical tests. Figure 8.19 allocates the portfolios into six statistically distinct groups with some "overlapping" between groups. The groups are associated with ranks of "1" through "6" such that the higher the ranking the larger the upper tail average stochastic total cost. Each portfolio within a group has statistically equal upper tail average stochastic total cost. Figure 8.19 indicates that the upper tail average is the same for Portfolios Q, E, K, and L (Group 1). But, the results also indicate that the upper tail average is statistically the same for Portfolios E, K, L, 12% PM, and 18% PM (Group 2). The portfolios in these two groups that do not "overlap" can be considered as not statistically the same. That is, Portfolio Q is not statistically the same as the 12% and the 18% PM portfolios. "Overlaps" and statistical equality for portfolios in other groups can be interpreted in a similar fashion. Some of the conclusions from this analysis are as follows:

- Portfolio Q has the same upper tail average stochastic cost as Portfolios E, K, and L.
- Portfolio Q has lower upper tail average stochastic cost than Portfolios 12% PM, 18% PM, P, J, M and N.
- Despite the "overlaps" the pattern for these results are similar to previous results, i.e., the higher upper tail average stochastic costs tends to be higher for portfolios having more additional gas capacity and associated generation.

The tests for the equality of variances among the portfolios for the upper tail case were performed, but all of the variances were statistically equal because of the low number of observations.

A measure of the average risk compared to extreme risk is the difference between the stochastic and deterministic total costs against the upper tail average stochastic total cost. Figure 8.20 illustrates this measure. On the graph values closer to the origin generally designate portfolios with lower average and upper-tail risk. A portfolio that has the combination of the lowest average and upper-tail risk has desirable stochastic characteristics. Consistent with the other results, Portfolios E, K, Q and L demonstrate lower risk compared to other portfolios. Portfolio Q has the least average risk and upper-tail risk than Portfolios E, K, L, and 12% PM. This portfolio has lower average and upper tail risk due to the lower levels of additional gas capacity and associated generation in this portfolio. Negative values for this risk measure are addressed generally in the "Spark Spread" analysis section.

Figure 8.20 – Average and Upper-Tail Risk: 'All-In' Basis

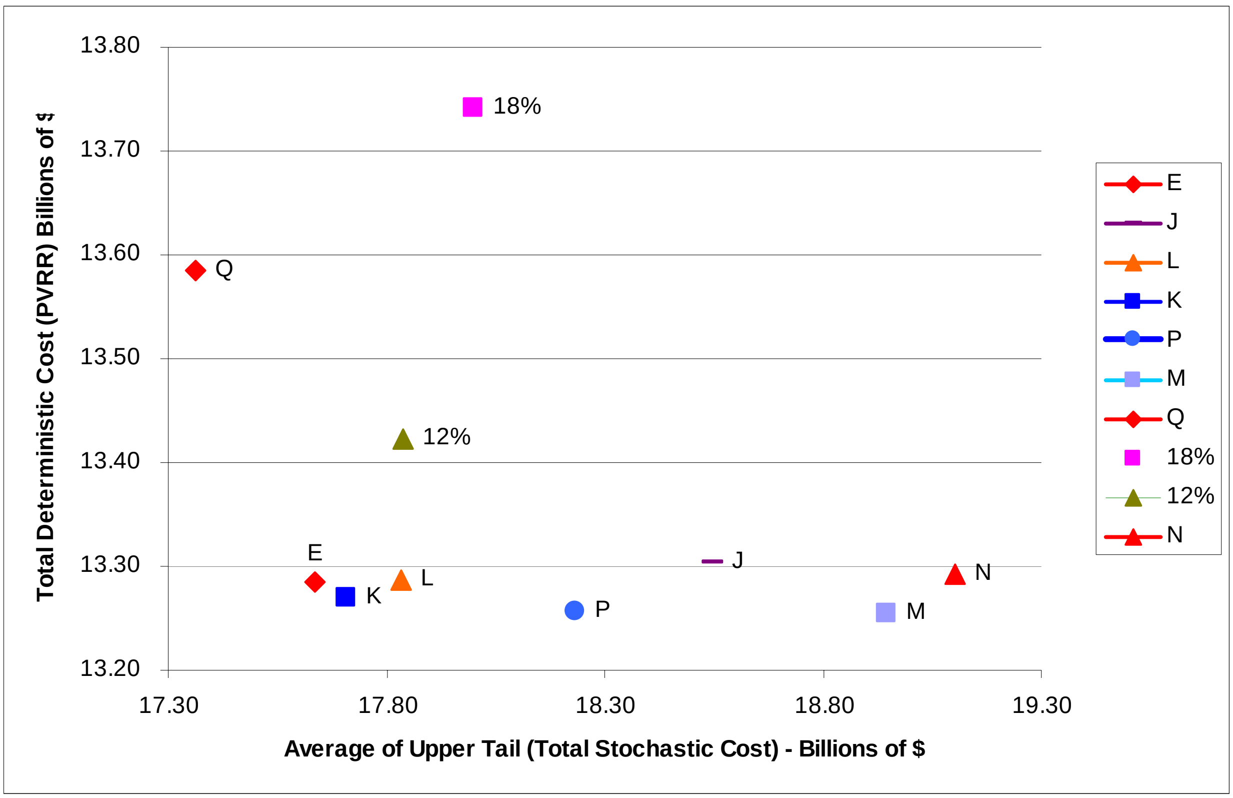


Risk/Cost Trade-off

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

Portfolios in the lower left hand quadrant of a cost/risk tradeoff represented in the next two charts should be considered as ideal. On the graph, values which are further to the left signify lower risk. In addition, values which are closer to the bottom of the graph, in general, signify lower overall cost. Figure 8.21 illustrates this trade-off for the various portfolios under consideration. Figure 8.21 compares total stochastic cost against the upper tail average stochastic variable cost. Since Portfolios Q, E, K, 12% PM and L are closest to the origin, these portfolios have the least risk relative to cost. Note that accounting for the full societal cost of ENS would discount the high ranking for the 12% PM portfolio, which has a significantly larger proportion of ENS costs relative to other portfolios. The high level of ENS results from the fact that the 12% PM portfolio has the least amount of supply and is therefore the least reliable portfolio. According to the results of the LOLP study described in Appendix N, the LOLP for a 12% planning margin would be greater than 4-in-10 years—much greater than the industry standard of 1-in-10. At a 15% planning margin, a 2-in-10 LOLP is expected.

Figure 8.21 – Total Cost vs. Risk: 'All-In' Stochastic Total Cost



Another measure of the risk/cost trade-off is the plot of the average total stochastic PVRR against the standard deviation of the PVRR for the 100 iterations. The average total PVRR is a cost measure and the standard deviation is a measure of the average variability of the portfolio. Statistical tests for these two measures were considered previously. Figure 8.22 illustrates these two measures for each of the selected portfolios. Similar to Figure 8.21, the portfolio with the lowest cost and risk should be closer to the origin.

Figure 8.22 – Average Stochastic Cost vs. Standard Deviation: 'All-In' Stochastic Total Cost

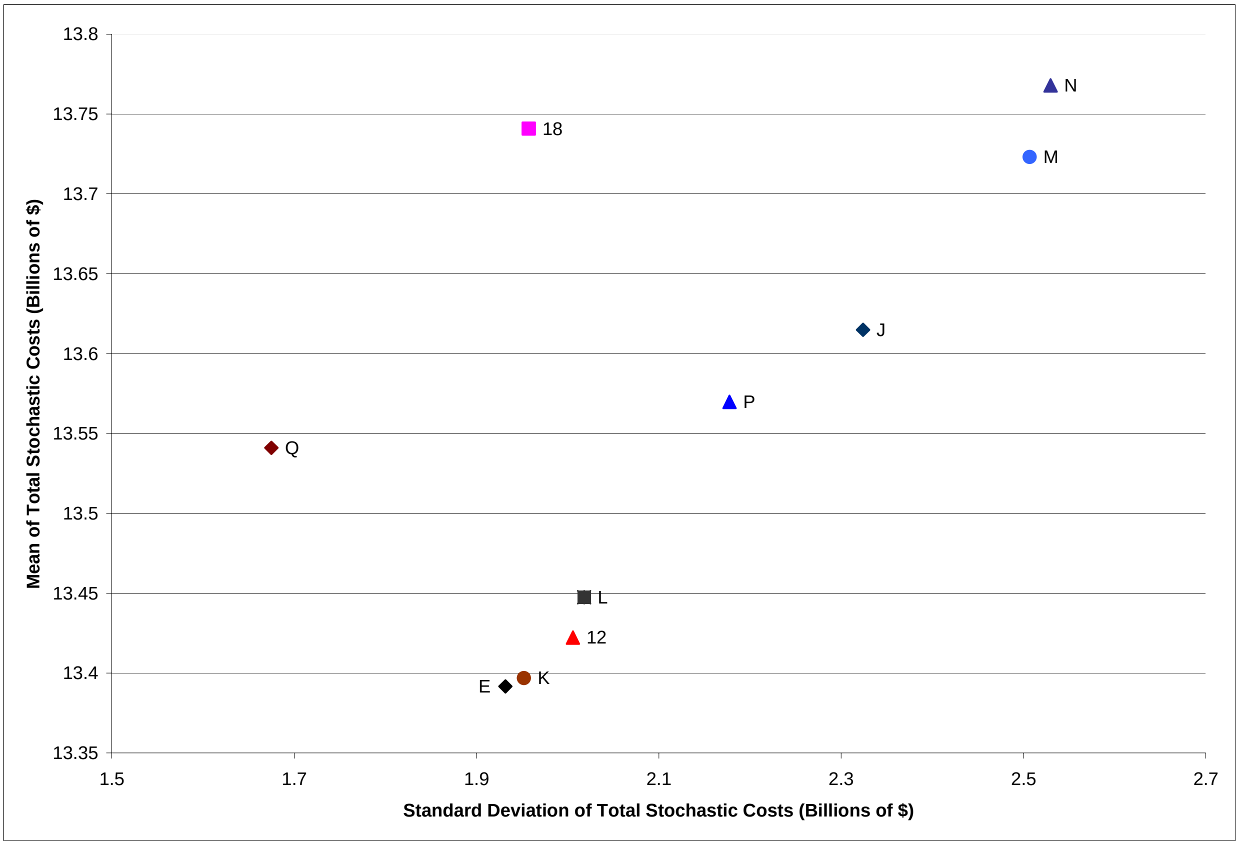


Figure 8.22 indicates that there is very little difference between Portfolios Q, E, K, L, and 12% PM.

Summary

Table 8.21 summarizes the results of the 'All-In' stochastic analysis by showing risk measure rankings for the top five portfolios for each measure. A value of "1" means that the portfolio performed the best for that particular measure and a value of "5" means that the portfolio performed the fifth best. Portfolios E, K, and Q ranked first or second for most of the risk measures.

Table 8.21 – 'All-In' Risk Measure Summary

Risk Measure	Rank (Top Five Portfolios for Each Measure)				
	1	2	3	4	5
1. Stochastic Average Total Cost (Fixed + Stochastic Var. Cost)	E	K	12%	L	Q
2. Paired-Difference Test of the Stochastic Average Total Cost	K,E		12%	L	J
3. Standard Deviation	Q	E	K	18%	12%
4. F-Test of Variances	Q	E,K, 18%, 12%			
5. Composite Measure of Average Risk (Figure 8.16)*	E	K	12%	L	Q
6. Statistical Test on Stochastic/Deterministic Difference	Q	K,E		18%, L	
7. Upper Tail Average Cost	Q	E	K	L	12%
8. Upper Tail Statistical Test	Q,E, K,L				12%
9. Stochastic Average against Upper Tail Average (Figure 8.20)*	Q	K	E	L	12%
10. Risk/Cost Trade-off #1 (Figure 8.21)*	Q	E	K	12%	L
11. Risk/Cost Trade-off #2 (Figure 8.22)*	E	K	12%	L	Q

* The measurements for Figures 8.16, 8.20, 8.21, and 8.22 were ranked in accordance with the distance from the origin on the graph for each portfolio.

Risk Measures for 'Spark Spread' Stochastic Runs

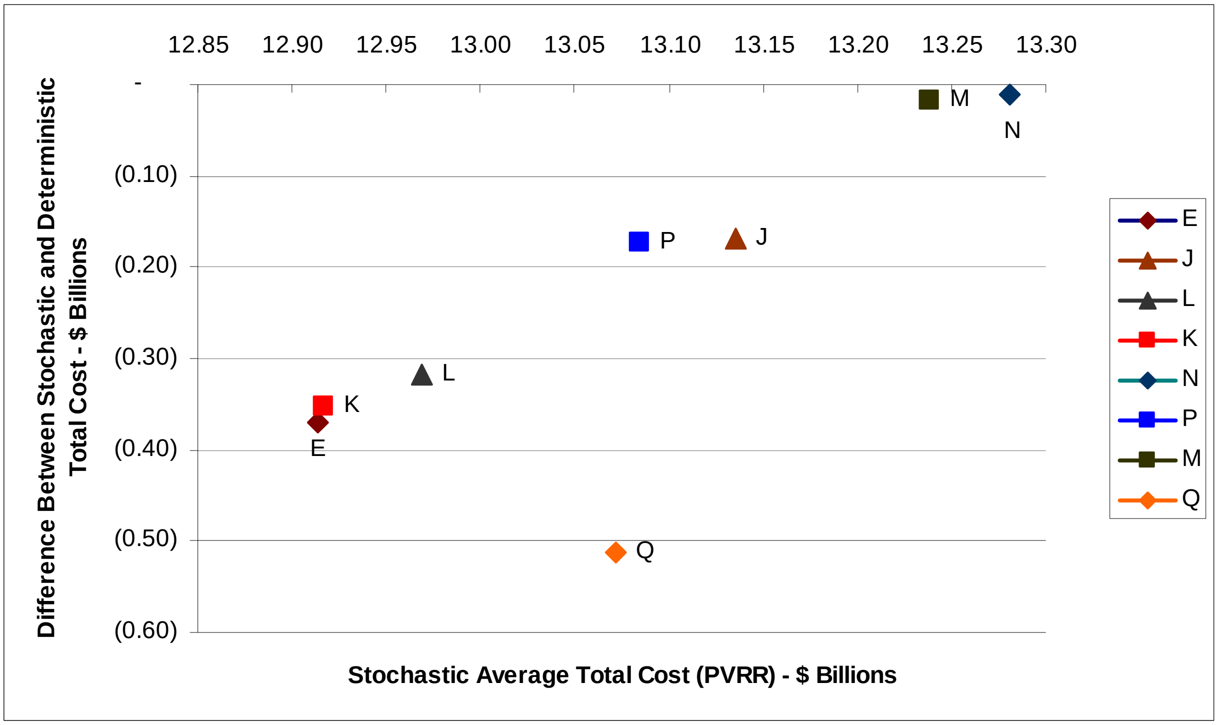
The 'Spark Spread' stochastic analysis allows only gas and electricity prices to move randomly, along with thermal outages. The purpose of this analysis is to measure the impact of volatility due primarily to price volatility. *The analysis inherently assumes no variability in the load forecast and in projected hydro generation*. The risk measures used for the 'Spark Spread' analysis are the same as those used for the 'All-In' analysis, but are not applied to the 18% and 12% planning margin portfolios.

Average Risk

Most of the results of the average risk measures are similar to the results found in the 'All-In' case with the exception of the 12% and 18% planning margin portfolios being excluded in the 'Spark Spread' analysis. One notable exception is the comparison of the difference between stochastic average cost and deterministic cost against stochastic average cost.

Figure 8.23 illustrates the composite view of two average risk measures for each of the eight portfolios consistent with the analysis summarized in Figure 8.16. The graph indicates that Portfolios E and K have the lowest composite average risk. This result is consistent with prior average risk measures. Portfolios P and J have medium average risk which is due to these portfolios having a larger amount of gas resource capacity. Portfolios M and N have the higher amounts of average risk associated with their relatively high concentration of new gas capacity and associated generation. Portfolio Q has a low value for the difference between the stochastic average and the deterministic PVRR because of the low levels of additional gas capacity in the portfolio. But, this portfolio has relatively higher values of the stochastic average total costs due to the higher fixed and capital costs associated with the additional coal generation units.

Figure 8.23 – Composite Measures of Average Risk: 'Spark Spread'



The difference between the stochastic average and the deterministic is negative, i.e., the stochastic average cost is less than the deterministic cost. In the "Spark Spread" analysis the two primary variables exhibiting volatility are gas prices and electric market prices, which are strongly correlated. The negative values indicate that the most economic use of market and gas generation is occurring. Portfolio Q has the largest negative value due to gas and market prices being lower than the cost of coal generation for iterations having low gas and electric market prices. For these iterations, coal generation is displaced by either cheaper gas generation or market purchases. So, the additional gas generation and market purchases have to cover the displaced coal generation and the growth in load obligation. With the iterations having moderate or high gas and market prices, coal generation has a relatively high capacity factor. So, the additional gas generation and market purchases only have to cover the growth in load obligation. That is, there is more potential generation subject to the lower gas and market prices than in the moderate or high case. The effect is to lower the stochastic average PVRR below the deterministic PVRR. Portfolio Q has the largest negative difference because it has more additional coal capacity and generation. Portfolios M and N are the least negative because these portfolios have no additional coal capacity and are experiencing only the economic use of gas generation and market purchases.

The difference between the average stochastic and deterministic PVRR is usually positive for the 'All-In' case (see Figure 8.17) because two additional variables are adding to the volatility and

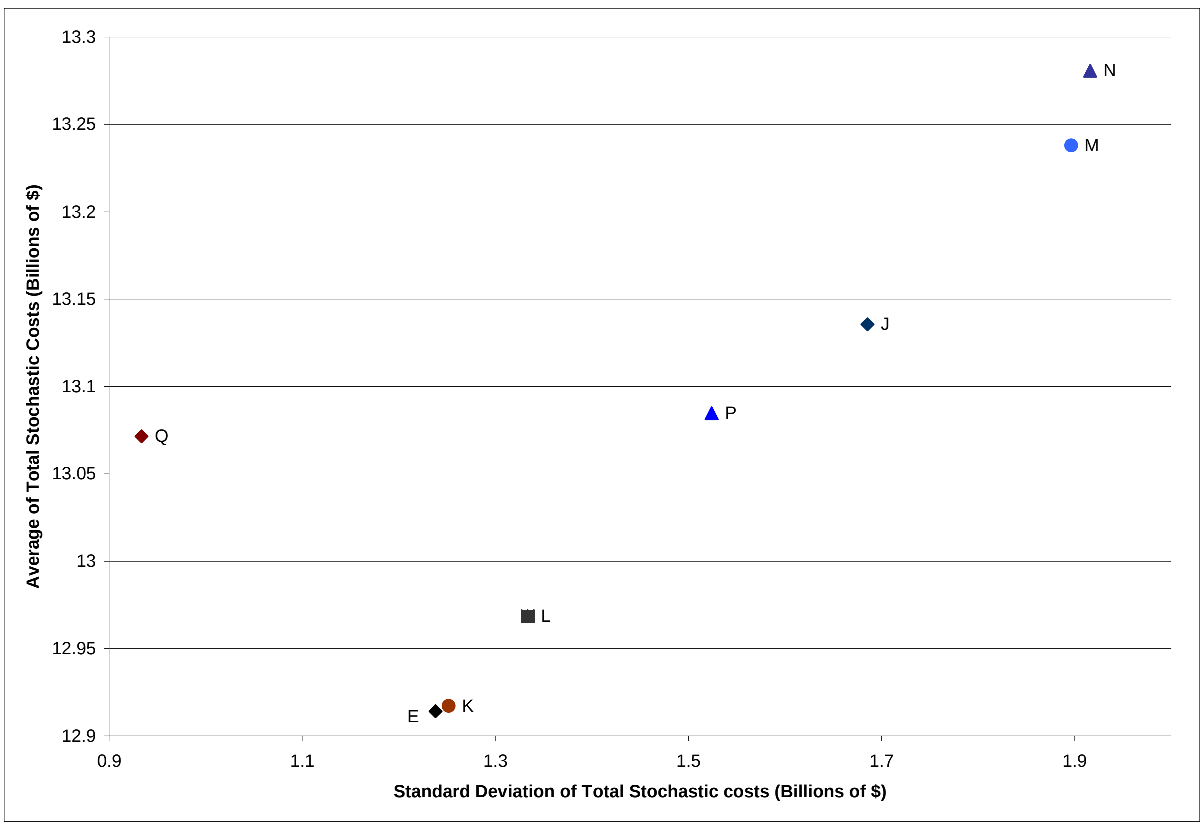
PVRR, i.e., load and hydroelectric availability. Portfolio Q represents the exception to this result due to the additional coal capacity and generation.

Risk Exposure
The results and patterns of the risk exposure measures are similar to the results found in the 'All-In' case with the exception of the 12% and 18% planning margin portfolios being excluded in the 'Spark Spread' analysis.

Risk/Cost Trade-off
Most of the results of the risk/cost trade-off measures are similar to the results found in the 'All-In' case with the exception of the 12% and 18% planning margin portfolios being excluded in the 'Spark Spread' analysis.

Two important measures of risk/cost trade-off are shown in Figure 8.24. These measures are the average stochastic total cost compared against the standard deviation of the stochastic total cost.

Figure 8.24 – Average Stochastic Cost vs. Standard Deviation:'Spark Spread' Stochastic Total Cost



Consistent with the 'All-In' case there is little apparent difference between Portfolios K, E, L, and Q.

Summary

Table 8.22 summarizes the results of the 'Spark Spread' stochastic analysis by showing risk measure rankings for the top five portfolios for each measure. A value of "1" means that the portfolio performed the best for that particular measure and a value of "5" means that the portfolio performed the fifth best. As with the 'All-In' analysis, Portfolios E, K, and Q ranked first or second for most of the risk measures.

Table 8.22 – 'Spark Spread' Risk Measure Summary

Risk Measure	Rank (Top Five Portfolios for Each Measure)				
	1	2	3	4	5
1. Stochastic Average Total Cost (Fixed + Stochastic Var. Cost)	E	K	L	Q	P
2. Paired-Difference Test of the Stochastic Average Total Cost	K,E		L	P,Q, L	
3. Standard Deviation	Q	E	K	L	P
4. F-Test of Variances	Q	K,E, L			P,J
5. Composite Measure of Average Risk (Figure 8.23)*	E	K	L	Q	P
6. Statistical Test on Stochastic/Deterministic Difference	Q	E	K	L	P,J
7. Upper Tail Average Cost	Q	E	K	L	P
8. Upper Tail Statistical Test	Q	K,E		L	P
9. Stochastic Average against Upper Tail Average*	Q	E	K	L	P
10. Risk/Cost Trade-off #1 *	Q	E	K	L	P
11. Risk/Cost Trade-off #2 (Figure 8.24)*	E	K	L	Q	P

* Measures were determined from the distance of the paired value from the origin.

Conclusions

Based on the stochastic results, generally portfolios with fuel diversity in capacity additions and associated generation exhibited less risk than those that did not, i.e. portfolios with heavy reliance on additional gas capacity. This result is due to gas price volatility. The only exception to this was Portfolio Q which had three coal units. Since there is less gas and more coal capacity in this portfolio, there is less opportunity for gas price volatility to negatively impact production costs. As a result Portfolio Q also performed well in the stochastic analysis.

These stochastic results can be used in combination with deterministic cost to identify which portfolios should go on to the next stage of risk analysis. Portfolios selected for Scenario analysis included those portfolios that performed well in deterministic and stochastic analysis, i.e., those portfolios that are low cost or low risk. These portfolios are L, E, K, Q, P, and M. Portfolios that had higher costs or risks were excluded from Scenario risk analysis. These portfolios are J, N, and 18% PM. The stress portfolio, 12% PM, was excluded due to its poor performance with respect to system reliability.

Scenario Risk Simulations

Three types of risk associated with portfolio analysis were evaluated within this IRP. These risk types—Paradigm, Scenario, and Stochastic—were discussed in Chapter 4. This section describes the results of the Scenario risk evaluation process. This type of risk is characterized by fundamental changes made to the expected value of some parameters. Assumed values (as opposed to simulated values) for specific parameters were used to test certain portfolios' sensitivities to a specific Scenario risk. Two possible fundamental changes to current modeling assumptions were investigated for their potential impact on the PVRR: CO_2 allowance costs and high gas costs.

CO_2 Allowance Cost Scenarios

CO_2 emissions are not currently regulated but may be in the future. The base case assumes a 50% probability of an $8/ton allowance cost (in 2008 dollars) starting in CY 2010, increasing to a 100% probability of occurrence by CY 2012. Although this is PacifiCorp's most likely estimate of carbon tax impacts, there is a chance, although not quantifiable, that the tax will be higher or non-existent. Since the probability of either case occurring is unknown, the impact of this assumption on the portfolios is best tested through Scenario risk simulations.

Assumptions

$0, $10, $25, and $40 per ton scenarios were evaluated through the IRP model against six portfolios. Similar to the base case treatment of the $8/ton allowance cost assumption, a cap and trade program for CO_2 allowances beginning in 2010 was modeled. A maximum allowable amount of system-wide CO_2 emissions was fixed at the year 2000 level. This assumption is in line with the McCain-Lieberman proposed legislation but less strict than the Kyoto Protocol. All thermal plants contribute to the amount of CO_2 emitted for the system. When annual emissions exceed the cap, each ton over the cap is charged the allowance rate. If system wide emissions are below the cap, a credit is applied to each ton emitted under the cap.

The low cost and low risk portfolios, K, L, E, and Q as well as the lowest-cost deterministic portfolios, M and P, were modeled for these scenarios. For each case, the allowance costs began to phase-in in 2010 at a 50% likelihood of occurrence with the cost of the allowance escalated from the base year 1990[24]. In 2011, the likelihood of a CO_2 tax regime increases to 75% of the fully escalated rate and by 2012, the allowance is fully implemented. This phase-in assumption is consistent with the methodology used in the base case.

Three variables are modified in the CO_2 scenarios; electric market clearing prices, gas prices, and emissions allowance costs. PacifiCorp contracted with ICF Consulting in order to develop projections for each of these inputs under the various CO_2 scenarios. ICF used their national multi-client industry model to develop the projections. The EPA frequently uses this model for analyzing proposed policy changes that impact the energy industry. This model is built upon pure industry fundamentals; therefore, PacifiCorp did not provide market assumptions, only CO_2 allowance values. ICF model runs produced gas market and NO_X and SO_2 pollutant allowance values that were then used in PacifiCorp's MIDAS model to produce electric market prices for the case scenarios.

[24] A base year of 1990 dollars was used for allowance cost calculations in accordance with the Oregon Order 93-695.

A new stream of forward market prices was generated for each CO_2 allowance level case reflecting impacts to power generation in the region. Figures 8.25 and 8.26 show plots of east and west market prices for each CO_2 case. After 2010, the price streams radically diverge. Prices in the $0/ton cases for both markets are 8-10% less than the base case estimates. The $10/ton case prices are 2-10% higher than base in later years, the $25 case prices are 30-40% greater and the $40/ton prices are 70-80% greater than base.

Figure 8.25 – Palo Verde Average Annual Forward Prices by Fiscal Year

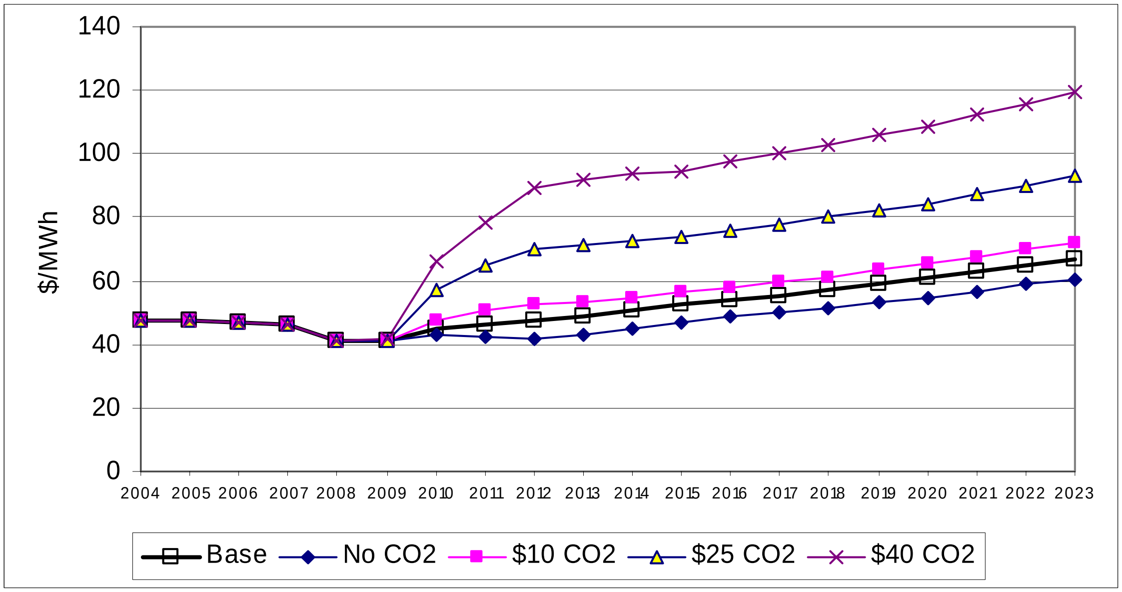
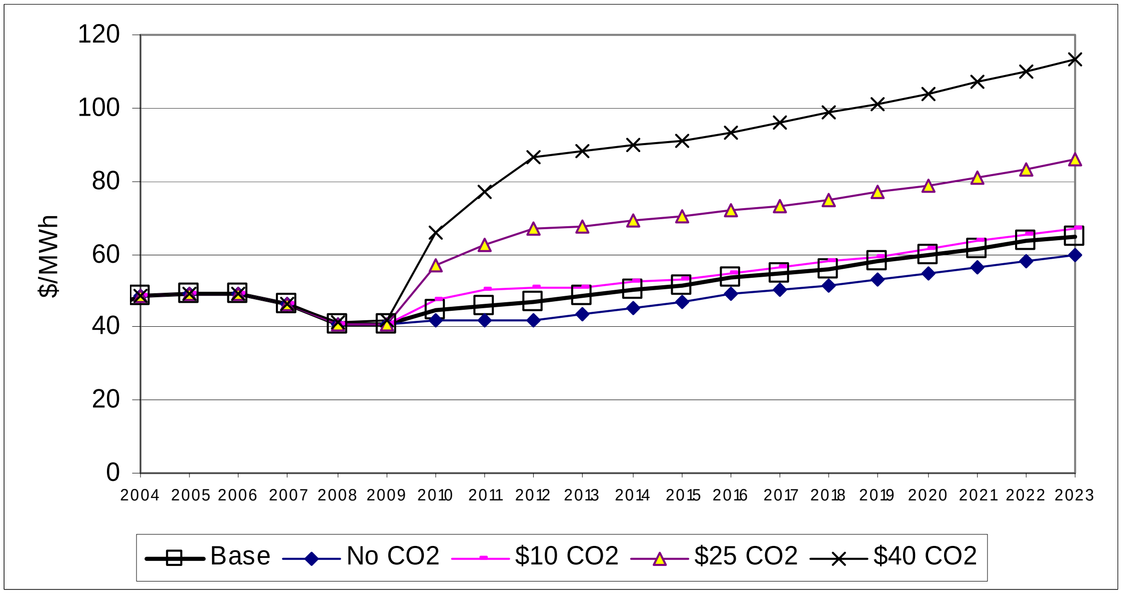
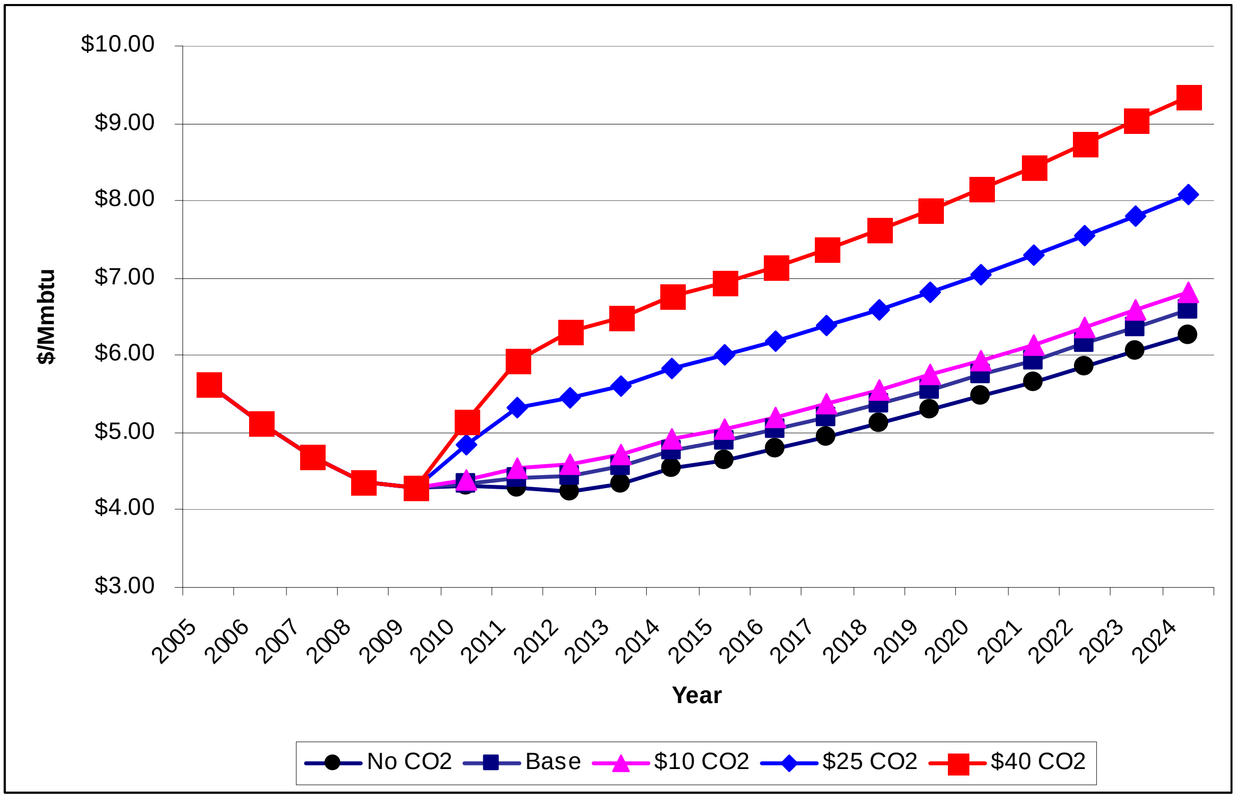


Figure 8.26 – Mid-Columbia Average Annual Forward Prices by Fiscal Year



New gas price forecasts were also estimated for each CO_2 case. Figure 8.27 shows these prices for the west on a calendar year basis, which follow a similar trend to the market prices above. Combined, these energy market prices are a large driver in determining model dispatch for these CO_2 cases.

Figure 8.27 – West Average Annual Forward Gas Prices by Fiscal Year



In addition to gas and market price adjustments for each change to CO_2 level, the assumptions for allowance costs for NO_X, and SO_2 are also adjusted to better reflect the estimated scenario impacts. Allowance costs for both pollutants are inversely related to the CO_2 allowance cost. As the carbon allowance increases, national coal generation is expected to decrease which will lead to a large supply of available NO_X and SO_2 allowances, decreasing their value.

<u>Observations</u>

- The average portfolio PVRR escalates with the increase of CO_2 allowance cost rate through $25 then declines for the $40 case where emissions credits outweigh increased fuel and market prices.
- New and existing coal unit operations decrease with the increase of CO_2 allowance cost rate, prompting an increase in market purchases and a decrease in market sales across the entire system.
- Total 2010-2025 CO_2 emissions at the $40/ton allowance cost rate are about 83% of emissions allowed based on the calendar year 2000 system wide allotment.
- CO_2 stresses impact the relative ranking of portfolios, measured by PVRR.

- For all portfolios, the capacity factors of CCCTs increase by FY 2015[25] from 59% for the $0/ton case to 92% for the $40/ton case.
- Similarly, for all portfolios the average capacity factors of coal units in FY 2015 vary from 90% for the $0 case to 47% in the $40 case.

Using PVRR as a measure, Portfolio Q placed first at $0/ton; Portfolio M, All Gas, was least cost for all other cases. Figure 8.28 displays the PVRRs by portfolio for each case. Table 8.23 lists PVRR values by portfolio for each CO_2 case in millions of dollars.

Figure 8.28 – PVRR Results by CO_2 Level

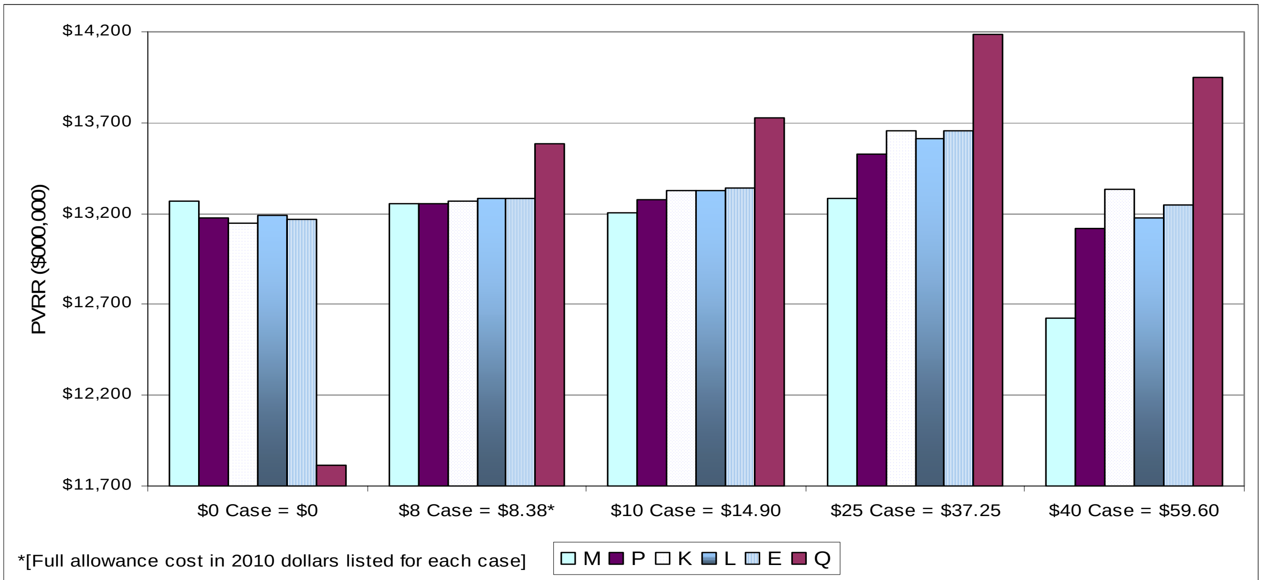


Table 8.23 – PVRR Results by CO_2 Level

Portfolio	CO2 $/Ton				
	$0 Case = $0	$8 Case = $8.38	$10 Case = $14.90	$25 Case = $37.25	$40 Case = $59.60
M	13,269	13,256	13,207	13,283	12,621
P	13,179	13,258	13,273	13,524	13,117
K	13,149	13,269	13,329	13,656	13,334
L	13,187	13,286	13,326	13,614	13,174
E	13,165	13,285	13,339	13,657	13,244
Q	11,816	13,585	13,725	14,187	13,947
Min	11,816	13,256	13,207	13,283	12,621
Min portfolio	Q	M	M	M	M
Max	13,269	13,585	13,725	14,187	13,947
Max portfolio	M	Q	Q	Q	Q
Total Spread	1,454	329	518	904	1,326

The overriding driver to the PVRR results is emissions credits. This analysis assumes that a perfect cap and trade market exists such that there will be a purchaser for each ton of CO_2 emitted below the assumed cap through the term of the study. Portfolio M generates substantial credits by reducing existing coal operations and running new and existing gas plants more

[25] FY 2015 was selected for this performance measure since all new generation resources are installed at this point and the carbon allowance is fully implemented.

frequently. Every modeled portfolio generates at least $3 billion in emissions credits in the $40/ton case compared to only $300-$500 million in the $0 through $10 cases. Portfolio M receives almost $6 billion in credits at a $40 allowance cost.

Although the corresponding high gas and electric market prices create lower fuel costs for the portfolios with additional coal resources then in other portfolios, allowance credits outweigh the added fuel costs for the All Gas Portfolio M, especially in the $40 case. The amount of carbon emitted relative to the cap from FY 2010-2025 is lowest for the All Gas Portfolio and therefore this portfolio receives the largest emissions credits. However, this portfolio is also most significantly impacted by the high fuel prices in the $25 and $40 cases with a larger magnitude of increase between cases compared to the other portfolios.

The results of Portfolio Q, the heavy coal portfolio, also stand out. In the $0/ton case, new and existing coal plants are running heavily with low fuel costs but carbon emissions 4% above the year 2000 system cap. No other portfolio in the $0/ton case emits above the system cap. The result is a low cost portfolio. As the CO_2 allowance increases, the portfolio runs coal less but doesn't have as much gas resource as the other portfolios. Its fuel costs remain lowest but emissions credits are not as substantial as the other portfolios, keeping it as the highest cost portfolio for all remaining cases. The cross over point for CO_2 allowance cost at which the heavy gas and heavy coal portfolios reach equilibrium is approximately $6.50/ton.

An additional point to consider when reviewing these results is the potential impact on portfolio ranking if an IGCC resource with sequestration was substituted for a modeled pulverized coal unit. The most recent cost estimates show that variable costs increase by more than $10/MWh for carbon capture and sequestration for either an IGCC unit or a pulverized coal unit and 90% of the CO_2 emissions are removed through this process.

From the IGCC "all-in" cost comparison provided in Figure 6.1, a carbon allowance value of $33/ton was identified as the cost-effectiveness crossover point between a pulverized coal unit and an IGCC unit with carbon capture and sequestration. This finding can be extrapolated to the results of the CO_2 allowance cost scenario in Figure 8.28 without additional modeling. For example, if the FY 2011 pulverized coal unit in Portfolio E was replaced with an IGCC unit, the IGCC portfolio results would be slightly greater than Portfolio E in the $25 case and slightly less than Portfolio E for the $40 case. Also within these high cases, this new portfolio would be greater than Portfolio M and less than Portfolio Q.

PacifiCorp currently estimates that the most likely outcome of future carbon regulation will produce $8/ton allowance prices which are reflected in the base case assumption. This analysis is useful for comparing possible outcomes but does not provide a basis for developing a hedging strategy against carbon regulation risk.

<u>Conclusions</u>

- There is little impact to PVRR or differentiation between portfolio performance at the base allowance cost assumption ($8/ton). Significant differences occur at the low- and high-end CO_2 cases.

- Increasing CO_2 allowance costs will have far-reaching and somewhat unexpected impacts to the energy industry, including significant increases to electric and gas market prices.
- Fuel switching from coal to gas could occur, reducing the amount of overall emissions but increasing reliance on natural gas.
- At the high allowance values, carbon capture and sequestration may become a cost effective alternative to traditional pulverized coal if feasible at the time.
- A mix of new resource types will help to reduce the risk of high system costs due to environmental pollutants and fuel cost.

High Gas Price Scenario

The goal of this scenario is to test selected Portfolios' sensitivity to a large fundamental increase in gas prices. Since electric market prices are highly correlated to gas prices, they are also expected to increase proportionately with gas prices in this scenario.

<u>Assumptions</u>

Since the base case gas forecast was developed in June 2004, prices have increased. A preliminary gas forecast planned for use in PacifiCorp's December 31st official price forecast for CY 2005 to 2015 was used. This forecast, derived from PIRA Energy's most recent long term natural gas price forecast, is on average \$2.27/MMBtu higher at Henry Hub than the gas forecast used in the IRP base case. Therefore, to create a high gas sensitivity case, this price forecast was used as the starting point and was increased by 10%. In addition, a real escalation rate of 0.5% per year beginning in CY 2016 was used. The long-term real escalation adjustment reflects the possibility of gas demand outpacing gains in production in the long term. The high gas price forecast was then used in the MIDAS model to generate a consistent "High Gas" power price forecast.

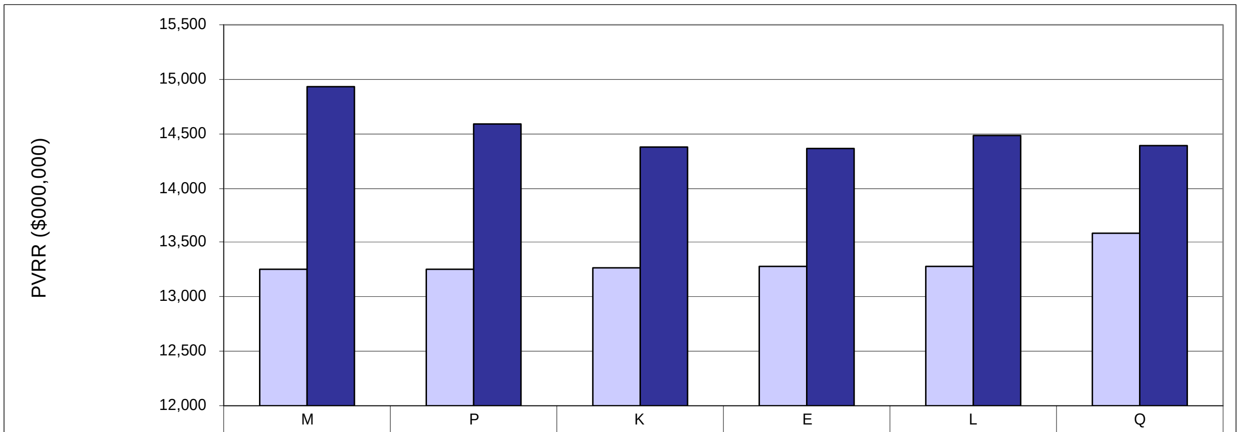
The low cost and low risk portfolios, K, E, L and Q, as well as the lowest cost deterministic portfolios, M and P, were modeled for this scenario.

<u>Observations</u>

- All Portfolio PVRRs increase between 6% and 13%.
- Portfolio M, the All Gas Portfolio, is impacted most significantly. It changes rank from first among deterministic runs to 6th in this scenario run.
- Portfolios K, E, and Q are tightly grouped within \$20 million of each other.
- In all portfolios, capacity factors of the gas resources decline in FY 2015 by 1-4%, lowering O&M and start-up costs compared to the base case runs.
- Market purchases and Front Office Transactions are exercised more fully, illustrating the impact of high fuel prices on unit dispatch.

Figure 8.29 shows the PVRR base and High Gas Price scenario results for the six portfolios.

Figure 8.29 – PVRR Base vs. High Gas Prices



	M	P	K	E	L	Q
Base	13,256	13,258	13,269	13,285	13,286	13,585
High gas and market	14,934	14,583	14,374	14,370	14,488	14,390

<u>Conclusions</u>
To reduce the impact of high gas prices, the optimal dispatch reduces operation of gas units and relies more heavily on market and coal resources. The relatively insignificant difference between portfolio PVRRs occurring in the base case does not carry over into a High Gas Scenario. The gas-heavy portfolio, Portfolio M, is clearly impacted much more than portfolios with a mix of new gas and coal generation since coal prices are not impacted with this scenario. The Scenario risk of a significant increase to gas and market prices is managed with a range of generation resource types including renewables and an effective hedging strategy that is not reflected in this analysis. Note that the High Gas Scenario represents an extreme market case.

CUSTOMER IMPACT EVALUATION RESULTS

This section characterizes the total costs of each candidate portfolio on a per-MWh basis. Describing cost per unit of energy better represents the impact on customer rates than the total PVRR. It also helps reflect the rate changes, which might be required moving from one year to another. This analysis, while providing an indication of rate direction, does not represent rates fully allocated by state and customer class; rather, it considers only the incremental costs of the new resource additions and variable operating costs of generation supply. Present Value of Revenue Requirements is used assuming:

- PVRR discounted at an after-tax weighted average cost of capital (7.176%)
- Nominal dollars for both variable and fixed cost are used for this customer impact analysis

Revenue Requirements Impact

The IRP Footprint

The IRP customer impacts calculation includes only the $/MWh rate impacts associated with the IRP "footprint" as compared to total PacifiCorp historical $/MWh (CY 2003 actual retail $/MWh was used for comparison). The methodology used in this IRP is much the same as that of the previous IRP with two exceptions: first, it has been requested that PacifiCorp subtract depreciation from the retail rate and, second, only the portfolios that were evaluated in the scenario analysis are included in this analysis.

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

Customer Impact Calculation

The methodology for the IRP customer impact calculation is as follows: portfolio $/MWh is calculated annually by dividing the total nominal revenue requirement of the IRP footprint by the IRP load projections. Each year's $/MWh result is compared with the previous year's value to derive the $/MWh increase or decrease. This $/MWh change is then divided by calendar year 2003's actual retail rate less depreciation of $42.02/MWh. (The CY 2003 $/MWh was chosen as a benchmark anchor to which all other years are compared.) This provides an "indicative" percentage increase attributed to the IRP portfolio for that year. Table 8.24 provides an example.

Table 8.24 – Annual Increase Calculation Example Using Portfolio E

Row		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1	IRP $/MWh Revenue Requirement	$ 9.42	$ 9.40	$ 9.05	$ 10.40	$ 12.12	$ 14.26	$ 15.26	$ 16.71	$ 18.53	$ 20.91	$ 21.57	$ 14.33
2	Year on Year change $/MWh		$ (0.02)	$ (0.35)	$ 1.35	$ 1.72	$ 2.15	$ 0.99	$ 1.46	$ 1.82	$ 2.38	$ 0.66	$ 1.21
3	CY 2003 Actual Retail Rate	$ 42.02	$ 42.02	$ 42.02	$ 42.02	$ 42.02	$ 42.02	$ 42.02	$ 42.02	$ 42.02	$ 42.02	$ 42.02	$ 42.02
	(less Depreciation)												
4	Annual Increase over CY 2003 Rate		-0.06%	-0.83%	3.21%	4.09%	5.11%	2.37%	3.47%	4.33%	5.66%	1.56%	2.89%

Explanation of Calculations

row 1 Annual revenue requirement for theis IRP portfolio divided by corresponding annual load
row 2 Current year minus prior year $/MWh increase/decrease
row 3 CY 2003 retail revenue less depreciation divided by retail MWh sold
row 4 Row 2 divided by 3

Effect on Rates

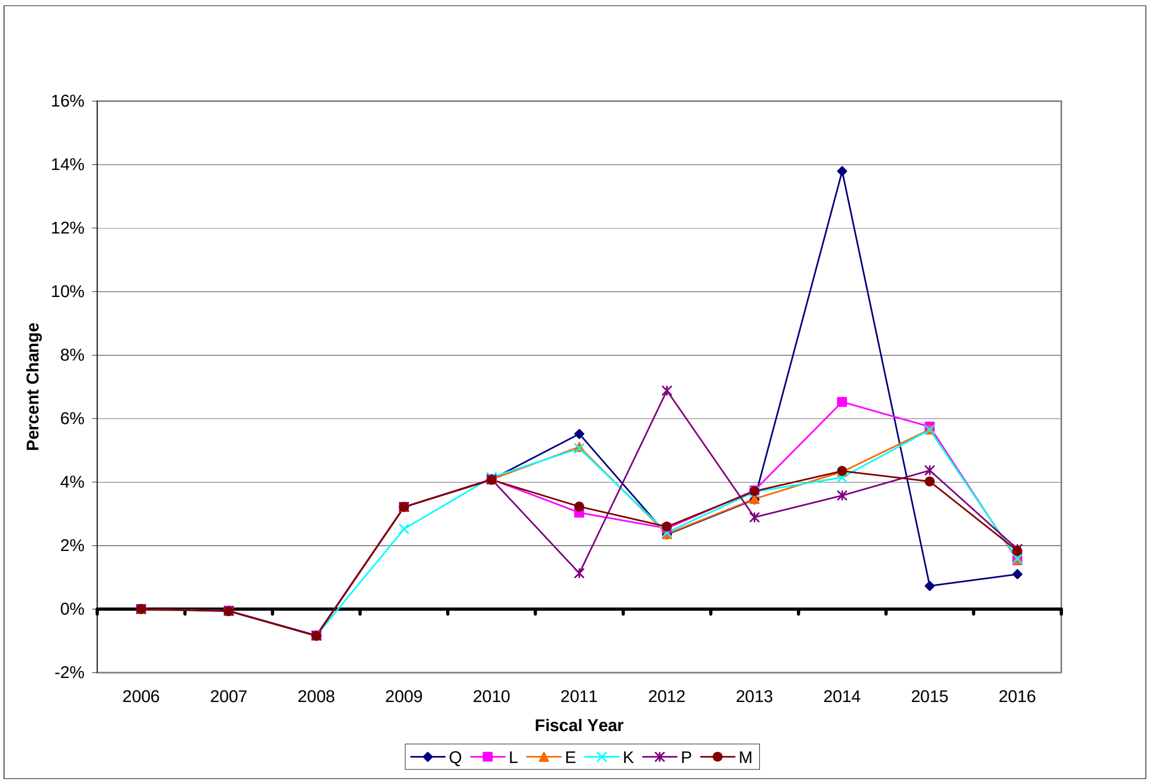
Because the IRP excludes costs common to all portfolios, the customer impacts calculation is only relevant when comparing one IRP portfolio against another. While the impact calculation provides yearly directional implications of rate changes associated with the IRP, it cannot provide a projection of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

Table 8.25 and Figure 8.30 show the calculation results in tabular and graphical form for the six candidate portfolios included in this analysis. (Note that results reflect portfolios before inclusion of DSM).

Table 8.25 – Annual Portfolio Retail Rate Increase over CY 2003

		Fiscal Year											
Portfolio	Description	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Average
E	Replace IGCC w/ WY PC	0.00%	-0.06%	-0.83%	3.21%	4.09%	5.11%	2.37%	3.47%	4.33%	5.66%	1.56%	2.63%
L	D, replace IGCC w/ PC	0.00%	-0.06%	-0.83%	3.21%	4.09%	3.04%	2.55%	3.74%	6.52%	5.75%	1.54%	2.69%
M	All gas with CCCT	0.00%	-0.07%	-0.84%	3.22%	4.07%	3.23%	2.60%	3.71%	4.35%	4.02%	1.83%	2.37%
K	C, replace IGCC w/ PC	0.00%	-0.06%	-0.83%	2.53%	4.15%	5.06%	2.41%	3.70%	4.15%	5.65%	1.58%	2.58%
P	CEM-selected portfolio	0.00%	-0.06%	-0.83%	3.21%	4.09%	1.13%	6.88%	2.89%	3.58%	4.37%	1.89%	2.47%
Q	Additional WY Transm/Coal	0.00%	-0.06%	-0.83%	3.21%	4.09%	5.52%	2.35%	3.45%	13.79%	0.73%	1.10%	3.03%

Figure 8.30 – Annual Rate Increases as a Percent of CY 2003 Retail Rates (Less Depreciation)



<u>Conclusions</u>

Even though the portfolios had similar PVRR values over the study period, rate impacts vary on an annual basis and closely follow the timing of plant additions.

SELECTION OF THE PREFERRED SUPPLY SIDE PORTFOLIO

This section describes how PacifiCorp chose a preferred supply side portfolio by assimilating the modeling and analysis results described above. Considerations relating to the risk evaluation and non-modeling factors are presented.

<u>Risk Evaluation Considerations</u>

The stochastic results indicate that increased diversification in new resource fuel type has the greatest positive impact on the performance of a portfolio with respect to the combination of cost and risk. To a lesser extent, reduced reliance on spot market purchases and greater dispatch flexibility (such as for IC Aero SCCTs) have positive impacts as well.

The Scenario risk results emphasize the positive diversification effect by showing that less diversification results in higher costs under high-risk scenarios: the "all gas" Portfolio M fares the worst under the High Gas Price Scenario, while Portfolio Q, with heavy reliance on coal, fares the worst under the high CO_2 allowance cost scenarios.

PacifiCorp therefore concludes that Portfolios E and K, with their superior performance on most risk measures and moderate showing with respect to the high-risk scenarios, are the best "preferred supply side portfolio" candidates.[26]

These two portfolios, which only differ by the gas technology selected for the FY 2009 resource, have virtually identical PVRRs and similar risk profiles.[27] The conclusion is that Portfolios E and K are indistinguishable from a modeling perspective; non-modeling factors therefore must determine which one is selected as the preferred PacifiCorp portfolio.

<u>Non-Modeling Considerations</u>

Since the only difference between Portfolios E and K is the technology type of the east-side gas resource added in FY 2009, PacifiCorp evaluated the desirability of the two technology types—CCCT and IC Aero SCCT—based on a number of subjective factors. *Portfolio E was selected as the preferred supply side portfolio on this basis*. The key factors that influenced the decision include the following:

- Synergies of plant knowledge. PacifiCorp has operating experience with CCCT technology, whereas the Intercooled Aeroderivative technology is new and presents minor technology risks.
- Ability to potentially share common plant facilities and spare parts with other CCCT units located in Utah.
- A CCCT has a lower heat rate than an IC Aero SCCT.
- A CCCT has lower per-MWh emission rates than an IC Aero SCCT.

In making its decision to select Portfolio E, PacifiCorp also weighed the advantages of IC Aero SCCT technology with respect to CCCTs. These include greater dispatch and build flexibility, and a lower capital cost. However, on balance, these advantages were not compelling enough to

[26] While the 12% planning margin stress case portfolio performs well deterministically and on certain "all-in" stochastic measures, it was deemed too risky given the potential for higher levels of Energy Not Served (ENS) and the associated societal costs.

[27] The gas technology portfolio comparison—Portfolio C versus Portfolio A—indicated that Portfolio C (IC Aero SCCTs replacing a CCCT) had considerably more spot market exposure, with $115.8 million in additional purchases versus $60.3 million less sales, relative to Portfolio A.

swing the decision in the favor of the IC Aero SCCT technology for the east-side FY 2009 resource.[28]

<u>Conclusions</u>

PacifiCorp has chosen Portfolio E as the preferred supply side portfolio. This portfolio was judged to have the best combination of risk characteristics and low PVRR. Its closest competitor, Portfolio K, also performs well in this regard. However, PacifiCorp's experience with CCCT technology, along with certain operational advantages, such as the ability to share common CCCT plant facilities and the generally lower heat rates and emission rates of CCCTs relative to the IC Aero SCCT technology, gives the edge to Portfolio E. Consequently, PacifiCorp performed Class 1 DSM analysis on Portfolio E in order to improve the portfolio PVRR.

CLASS 1 DSM PROGRAM ANALYSIS

This section describes the Class 1 DSM analysis for determining PacifiCorp's Preferred Portfolio. The Preferred Portfolio is the supply side preferred portfolio E, with the addition of Class 1 DSM programs. PacifiCorp's objective for adding Class 1 DSM to the supply side preferred portfolio E is to lower the PVRR. The creation and details of this portfolio are described below.

As outlined in Chapter 5, the Capacity Expansion Model was used to select the most cost-effective Class 1 DSM programs out of a selection of eight possible programs for the FY 2009-2015 period. The DSM proxy program options available for selection by the CEM are summarized in Table 8.26. These proxies were developed from three sources. The Cool Keeper Program and Idaho Irrigation Extensions were based on the option to continue these programs beyond their base case end date of 2014. The Irrigation Control proxy was based on the experience PacifiCorp obtained from the Idaho program over the last two years. The remaining four proxy Class 1 programs were based on program opportunities and costs from the DSM RFP 2003 proposals received. Each of these proxies have specific seasons, months, and hours that limit their operation based on the end uses being controlled. Proxy resources selected for the Preferred Portfolio will then be procured through an RFP process. The most cost-effective proposal will be the most *viable* cost-effective program, and will not necessarily address the same end-use as the proxy identified in the Preferred Portfolio.

[28] Note, however, that the IC Aero SCCT proxy resource was selected to address the west-side FY 2013 short position. A CCCT unit was considered too large, resulting in significant excess capacity. Also, enough commercial experience will have been gained to sufficiently alleviate concerns over technology risks.

Table 8.26 – DSM Proxy Program Options for the Capacity Expansion Model

Proxy DSM Resource Name	Location	Maximum Program Megawatts	Program Cost, $/kW-yr. ($2004)
Residential/Small Commercial Air Conditioning Control	West	45	58.35
Commercial Lighting Control	West	45	58.35
Commercial Electric Space/Water Heat Control	West	44	58.35
Irrigation Control	West	44	27.19
Commercial Cooling Control	East	44	58.90
Irrigation Control	East	44	27.19
Cool Keeper Program Extension	East	45	58.35
Idaho Irrigation Extension	East	44	27.19

Based on the CEM's solution, four of the eight potential DSM programs were selected for implementation. The programs and their start years are shown in Table 8.27.

Table 8.27 – CEM-Selected DSM Resources and Program Start Years

DSM Resource Name	Location	Maximum Program Megawatts	Start Year (FY)
Residential/Small Commercial Air Conditioning Control	West	45	2015
Commercial Cooling Control	East	44	2015
Irrigation Control	West	44	2011
Irrigation Control	East	44	2011

Using CEM's selected programs for guidance, a Portfolio was manually constructed using the preferred supply side Portfolio E, along with the CEM-selected DSM resources. (Note that the CEM-selected portfolio consists of a different resource mix than the preferred supply side portfolio, determined from risk analysis and non-modeling considerations.) The DSM program start years were adjusted to coincide with those of the in-service years of the earliest thermal resources to analyze the potential for resource deferral. A resource was deferred if the addition of a DSM program kept the system planning margin at or above 15 percent for that year.

Table 8.28 shows the resulting Portfolio E resource plan with new DSM programs added. The DSM programs have been renamed to the generic designation, "DSM, Summer Load Control". *Three resources were deferred as a result of the Class 1 DSM programs.*

- Utah Brownfield Pulverized Coal, from FY 2011 to FY 2012
- Utah dry cool CCCT, from FY 2009 to FY 2010
- West-side IC Aero SCCTs, from FY 2014 to beyond FY 2015

Table 8.28 – Portfolio E Resources with CEM-Selected DSM Programs

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

A deterministic simulation was run using Portfolio E with the CEM-selected DSM programs. The PVRR results for this overall preferred portfolio, along with those of the original Portfolio E, are shown in Table 8.29. The addition of the DSM programs reduces Portfolio E's PVRR from $13.285 billion to $13.150 billion, a $134 million decrease. The largest impact is on fixed costs, with a reduction of nearly $200 million. Offsetting the fixed cost benefit somewhat is an increase in variable contract and spot market purchase costs, along with lower spot market sales revenues.

Table 8.29 – PVRR Cost Components: Portfolio E with DSM vs. Original Portfolio E

COST COMPONENT ($000)	Portfolio E with DSM	Portfolio E	Difference	Percent Difference
Variable Costs				
Total Fuel Cost	10,526,748	10,568,614	(41,865)	-0.4%
Total Variable O&M Cost	1,000,585	1,004,686	(4,101)	-0.4%
Total Emissions Cost	(439,895)	(426,657)	(13,238)	3.1%
Total Start-up Cost	10,547	10,969	(422)	-3.8%
Variable Contract Cost	1,830,348	1,789,441	40,906	2.3%
Sales	(3,636,554)	(3,664,543)	27,989	-0.8%
Purchases	1,668,723	1,617,947	50,776	3.1%
Total Net Variable Power Cost	10,960,502	10,900,457	60,045	0.6%
Real Levelized Fixed Cost	2,184,993	2,384,066	(199,073)	-8.4%
Real Levelized DSM Cost	4,597	--	N/A	N/A
TOTAL PVRR	13,150,091	13,284,523	(134,432)	-1.0%

Conclusions

The addition of dispatchable DSM programs to portfolio E successfully met PacifiCorp's objective of discovering the least cost, risk informed portfolio. The new programs, in conjunction with the deferment of resources resulted in a PVRR reduction of $139 million.

Portfolio E, with dispatchable DSM included, is referred to as the *Preferred Portfolio* in the remainder of this document.

DSM DECREMENT ANALYSIS

In the DSM Decrement Analysis, the Preferred Portfolio was used to calculate the decrement value of various types of Class 2 programs following the methodology described in Chapter 5. PacifiCorp will use these decrement values when evaluating the cost-effectiveness of potential new programs between IRP cycles. Once new programs are implemented, their contribution to load reduction will be incorporated directly into the load forecast used for the next IRP.

Modeling Results

Table 8.30 shows the nominal results of eight decrement cases for each year of the planning period. Although no resources were deferred or eliminated from the portfolio due to the addition of Class 2 decrements, there is value in having to produce less generation to meet a smaller load.

Both residential air conditioning decrements produce the highest value for each location. Programs with this end use impact provide the most value to PacifiCorp's system since they reduce demand during the highest use hours of the year, summer HLHs. The commercial lighting and system load shapes with the highest load factors provide the lowest avoided costs. Much of their end use shapes reduce loads during a greater percentage of off-peak hours than the other shapes and during all seasons, not just the summer.

Table 8.30 – Nominal Avoided Costs for Decrements by Fiscal Year

		Decrement Values (Nominal $/MWh)							
Decrement Name	Actual Load Factor	2009	2010	2011	2012	2013	2014	2015	2016
EAST									
Residential Cooling	12%	54.57	48.52	52.45	47.42	49.12	49.49	49.10	52.60
Commercial Cooling	24%	43.28	41.27	44.72	42.21	43.67	44.23	43.45	47.22
Commercial Lighting	51%	36.75	36.86	39.37	37.99	38.89	39.90	38.71	41.88
System Load Shape	65%	38.52	39.02	40.74	39.52	40.59	41.70	40.60	44.37
WEST									
Residential Cooling	7%	42.74	43.99	51.70	55.41	57.15	58.22	57.68	61.34
Commercial Cooling	24%	39.52	41.05	45.91	49.34	49.17	49.56	49.61	52.26
Commercial Lighting	51%	38.65	39.31	43.46	46.59	45.73	46.79	47.05	49.82
System Load Shape	67%	38.78	39.74	43.57	47.16	46.69	48.15	47.50	49.92

	Decrement Values (Nominal $/MWh)								
Decrement Name	2017	2018	2019	2020	2021	2022	2023	2024	2025
EAST									
Residential Cooling	56.95	58.03	59.44	63.74	68.34	71.71	73.84	75.97	78.77
Commercial Cooling	48.46	51.33	53.72	57.53	63.94	67.73	65.71	71.64	73.88
Commercial Lighting	43.40	45.53	48.58	52.83	60.24	64.75	64.63	68.34	70.72
System Load Shape	45.70	47.83	50.34	55.03	62.11	65.88	65.98	69.56	71.86

	Decrement Values (Nominal $/MWh)								
Decrement Name	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
WEST									
Residential Cooling	63.12	64.02	64.85	68.59	68.38	71.55	73.25	74.80	78.05
Commercial Cooling	53.88	56.71	58.20	60.90	62.24	65.82	68.15	69.16	71.01
Commercial Lighting	51.13	53.96	56.12	58.62	60.55	63.68	65.66	67.09	69.07
System Load Shape	52.43	54.51	56.75	59.22	61.25	63.83	66.28	67.85	69.86

Figures 8.31 and 8.32 show the decrement costs for each end use with the average annual forward market price for that location.

Figure 8.31 – East Decrements by Fiscal Year

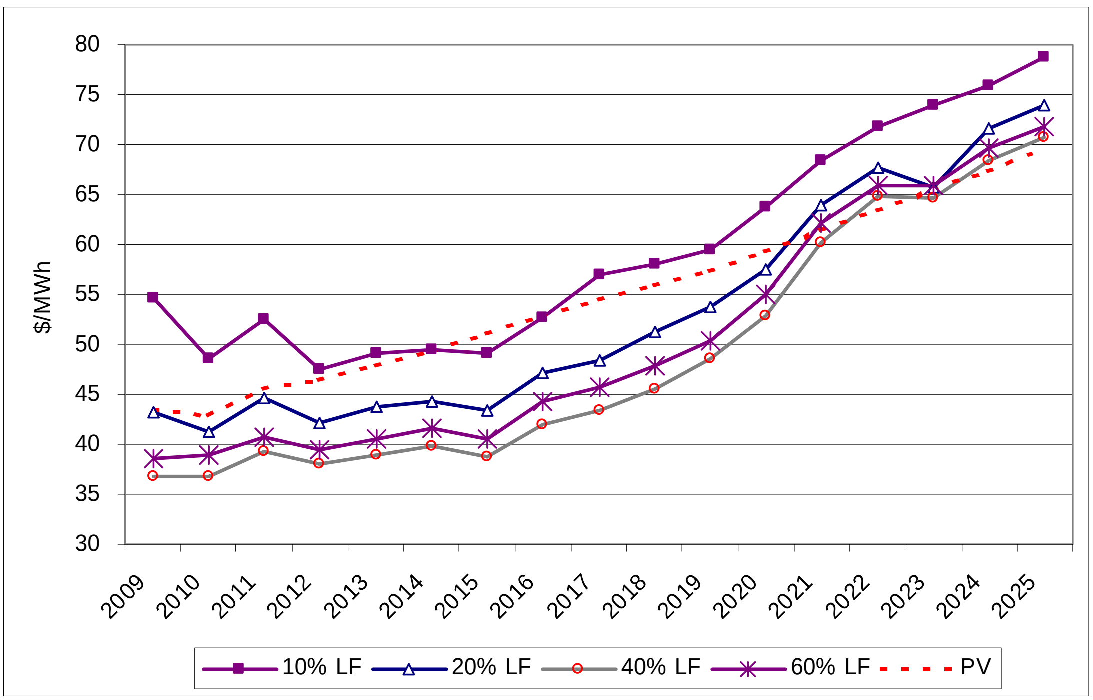
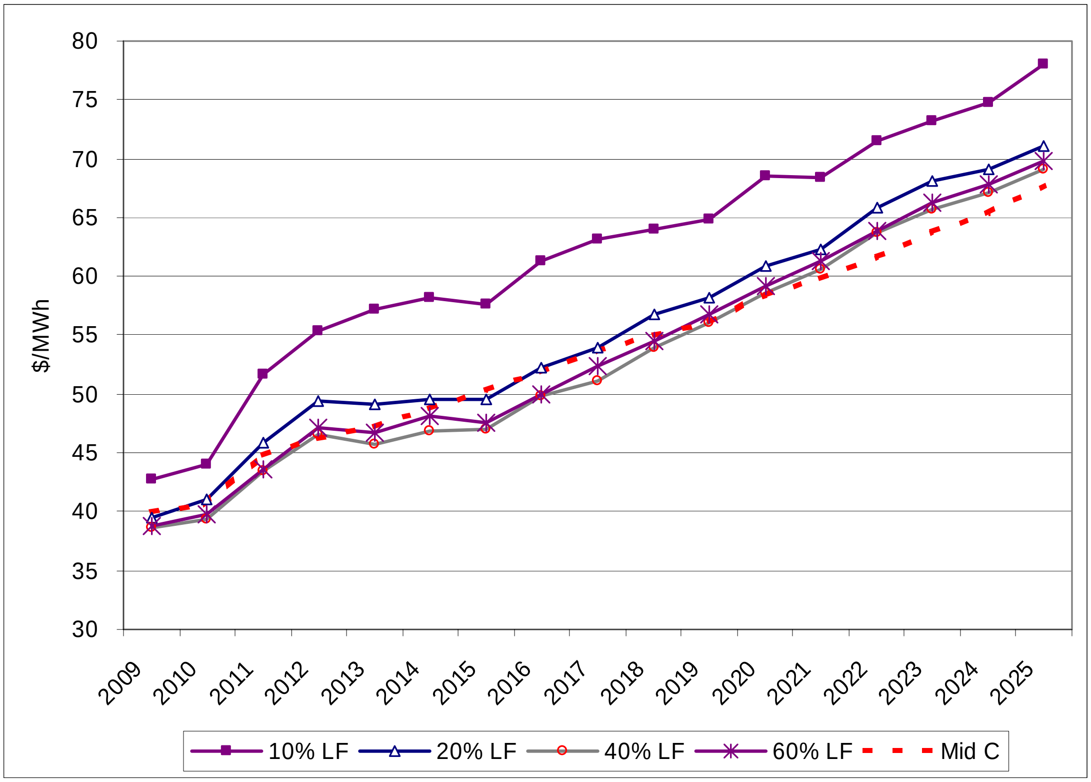


Figure 8.32 – West Decrements by Fiscal Year



<u>Conclusions</u>

Each decrement provides a unique value to the system. These results will assist in the evaluation of responses to forthcoming RFPs that will be issued for new Class 2 DSM programs. The estimated costs of implementing programs with similar end use load reductions will be compared to the calculated decrement values to help determine their cost effectiveness. A higher or lower decrement value doesn't necessarily mean that one program type is more cost-effective than another, only that system operation costs during those time periods differ.

STRESS CASE PORTFOLIO RESULTS

This section describes the results of simulating a number of portfolios deterministically to test the cost impacts of certain alternative portfolio design assumptions. These assumptions include:

- The Planning Margin level – high and low values
- Replacement of Front Office Transaction proxy resources with build-or-buy assets
- Accelerated procurement of an IGCC resource with updated technology characteristics
- The inclusion of Distributed Generation resources: Combined Heat & Power (CHP) and customer-owned standby generators

Planning Margin Portfolios

Two stress analyses were performed to determine the cost impact of using alternate planning margin assumptions when building IRP portfolios: "18% PM" and 12% PM". Reference Portfolio A served as the starting point for construction of the two stress portfolios, which are shown in Table 8.31 below.

Table 8.31 – Planning Margin Stress Portfolios

18% PM

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
East	Brownfield Coal	Utah-S						575					575
	Greenfield IGCC	Utah-N										368	368
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N									560		560
	IC Aero SCCT	Utah-N					174			174			348
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

12% PM

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
East	Brownfield Coal	Utah-S						575					575
	Greenfield IGCC	WY										368	368
	Wet Cool CCCT w/ DF	Utah-N									560		560
	IC Aero SCCT	Utah-N					87		87	87			261
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN										97	97

Compared to the preferred supply side portfolio, E, the following cost impacts are evident.

18% Planning Margin Portfolio

- The PVRR is $276 million higher than the PVRR for Portfolio E; operating and fixed costs are significantly higher due to the additional on-line capacity (3,156 MW of IRP proxy resources for the 18% PM Portfolio versus 2,823 MW added for Portfolio E).
- Spot market purchase costs are lower by $60 million, and sales revenues are higher by about $43 million.

12% Planning Margin Portfolio

- The PVRR is $140.5 million lower than the PVRR for Portfolio E; production and fixed costs are significantly lower due to less on-line capacity (2,447 MW of IRP proxy resources for the 12% PM Portfolio versus 2,823 MW for Portfolio E); however, total net variable costs are higher due to greater purchase costs and less sales revenues.
- Spot market purchases are significantly higher, by about $295 million; sales revenues are corresponding less, by $121 million.

Table 8.32 shows the PVRR cost components for the two planning margin stress portfolios, along with Portfolio E.

Table 8.32 – PVRR Cost Components: Capacity Planning Margin Portfolios vs. Portfolio E

COST COMPONENT ($000)	18% PM	12% PM	E
Variable Costs			
Total Fuel Cost	10,702,737	10,273,286	10,568,614
Total Variable O&M Cost	1,037,726	999,015	1,004,686

COST COMPONENT ($000)	18% PM	12% PM	E
Total Emissions Cost	(444,067)	(482,445)	(426,657)
Total Start-up Cost	10,935	10,667	10,969
Variable Contract Cost	1,761,621	1,880,319	1,789,441
Sales	(3,707,666)	(3,543,348)	(3,664,543)
Purchases	1,557,967	1,912,472	1,617,947
Total Net Variable Power Cost	10,919,252	11,049,966	10,900,457
Real Levelized Fixed Cost	2,641,698	2,094,091	2,384,066
TOTAL PVRR	13,560,950	13,144,057	13,284,523

Replacement of Front Office Transactions Portfolio

For this stress portfolio, the Front Office Transaction proxy resources for the west and east were removed (700 MW east, and 500 MW west). To compensate for these resource removals, CCCT resources were added in the east in FY 2009 and FY 2013, and the west in FY 2009. Table 8.33 shows the resulting stress portfolio with these resource substitutions.

Table 8.33 – Front Office Transaction Stress Portfolio

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
East	Brownfield Coal	Utah-S						575					575
	Greenfield IGCC	WY										368	368
	Dry Cool CCCT w/ DF	Utah-S				525				1050			1575
	Wet Cool CCCT w/ DF	Utah-N				560							560
West	Dry Cool CCCT w/ DF	WMAIN				586				586			1172
	IC Aero SCCT	WMAIN										194	194

Compared to the preferred supply side portfolio, E, the following cost impacts are evident:

- The PVRR is $639 million higher than the PVRR for Portfolio E.
- Spot market purchase costs and sales revenues are lower by $142.8 million and $106.2 million, respectively, reflecting the large relative increase in generation resources available.
- Front Office Transactions that more closely fit load shape are significantly more cost-effective than building or buying long-term assets.

Table 8.34 shows the PVRR cost components for the Front Office Transaction Stress portfolio and Portfolio E.

Table 8.34 – PVRR Cost Components: Front Office Transaction Portfolio vs. Portfolio E

COST COMPONENT ($000)	Without FO Transactions	Portfolio E	Difference	Percent Difference
Variable Costs				
Total Fuel Cost	11,474,494	10,568,614	905,880	8.6%
Total Variable O&M Cost	1,098,795	1,004,686	94,109	9.4%
Total Emissions Cost	(369,911)	(426,657)	56,746	(13.3%)
Total Start-up Cost	10,647	10,969	(322)	(2.9%)
Variable Contract Cost	823,363	1,789,441	(966,079)	(54.0%)
Sales	(3,770,698)	(3,664,543)	(106,155)	2.9%
Purchases	1,475,163	1,617,947	(142,784)	(8.8%)

COST COMPONENT ($000)	Without FO Transactions	Portfolio E	Difference	Percent Difference
Total Net Variable Power Cost	10,741,853	10,900,457	(158,605)	(1.5%)
Real Levelized Fixed Cost	3,181,839	2,384,066	797,773	33.5%
TOTAL PVRR	13,923,692	13,284,523	639,168	4.8%

Early IGCC Commercial Viability Portfolio

For this stress case portfolio, based on Portfolio E (the preferred supply side portfolio), the FY 2011 Utah pulverized coal resource is replaced by a 460 MW coal-fired IGCC resource with updated cost and operational characteristics. As discussed in Chapter 6, this portfolio assumes accelerated implementation of a commercially viable IGCC technology. Table 8.35 shows the resulting portfolio.

Table 8.35 – Early IGCC Commercial Viability Portfolio

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total MW
East	Greenfield IGCC	Utah-S						460					460
	Brownfield Coal	WY										383	383
	Dry Cool CCCT w/ DF	Utah-S				525							525
	Wet Cool CCCT w/ DF	Utah-N									560		560
West	Dry Cool CCCT w/ DF	WMAIN								586			586
	IC Aero SCCT	WMAIN								194			194

Table 8.36 compares the technology attributes of the original IGCC resource modeled and the updated IGCC resource used in this portfolio.

Table 8.36 – Technology Characteristics for IGCC Resources

Technology Characteristic	Original IGCC Resource	Updated IGCC Resource
Configuration	2 gasifiers, 2 "H" gas turbines, 1 steam turbine	3 gasifiers, 2 "7FB" gas turbines, 1 steam turbine
Unit Capacity (MW)	368	460
Capital Cost ($/kW)	2,171	2,350
Variable O&M ($/MWh)	1.83	1.80
Fixed O&M ($/kW-yr)	30.52	51.88
Availability (%)	75	90
SO_2 Emissions (lb/MMBtu)	0.03	0.01
NO_X Emissions ((lb/MMBtu)	0.05	0.02
Hg Emissions (lb/Trillion Btu)	0.60	0.24
CO_2 Emissions (lb/MMBtu)	205	205

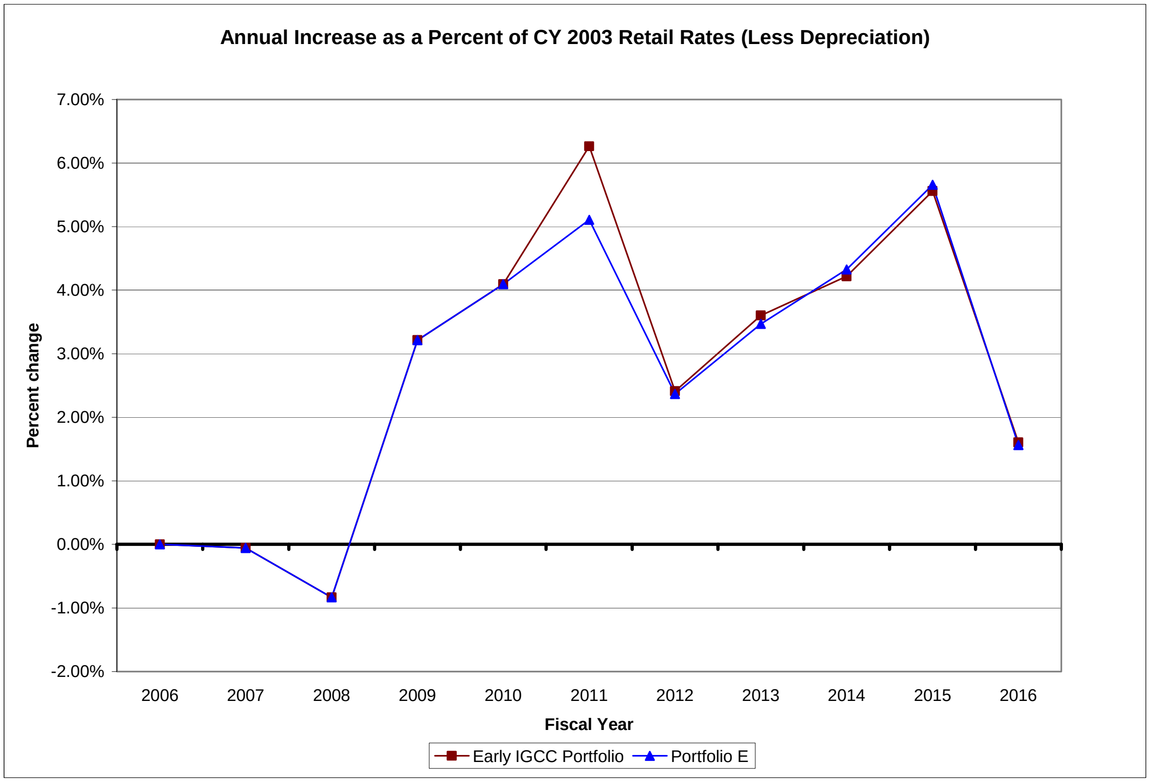
The PVRR for the IGCC Portfolio is $13.51 billion, which ranks it among the highest for all portfolios tested and slightly lower than the PVRR for IGCC-intensive Portfolio O.[29] The net variable power and capital cost PVRR components for the IGCC portfolio are $11.02 and $2.49 billion, respectively.

[29] Portfolio O includes two IGCC units modeled with the original technology data.

In relation to preferred supply side portfolio E, the PVRR for the IGCC stress case portfolio is $222 million higher. Significantly greater fixed costs and spot market purchases contribute the most to the PVRR difference. In contrast, the emission reduction benefit of IGCC technology helps the IGCC portfolio achieve a relative $70.3 million emission cost advantage.

Public Input Meeting participants requested that a customer impact calculation using the methodology described earlier in the Chapter be conducted on this portfolio. The IGCC portfolio produces an average annual rate increase of about 2.7 percent for FY 2006 to 2016, which is not significantly different from the impact calculation results for other portfolios. Figure 8.33 shows the year-to-year retail rate increases for the IGCC portfolio and the preferred supply side portfolio E.

Figure 8.33 – Portfolio Rate Impact Comparison, Early IGCC Commercial Viability vs. Portfolio E



Distributed Generation Portfolios

Two Distributed Generation stress analyses were performed using preferred supply side Portfolio E as the starting point. The purpose of these stress analyses is to help inform the IRP Action Plan.

Cogeneration

In this stress case, 90 MW of combined heat and power resources (CHP) were added to the west system in Fiscal Year 2013. As discussed in Chapter 3, some large commercial or industrial customers may install CHP to jointly produce electricity along with other forms of thermal or mechanical energy needed by their facility. Since this generation addition is assumed to be firm it reduced the need for IC Aero SCCT units in the west from two to one 97 MW unit. Table 8.37 shows the portfolio configuration with CHP additions.

Table 8.37 – Portfolio E Resource Additions with West CHP

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
East	Brownfield Coal	Utah-N						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
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								97			97
	CHP (2x45MW)	WMAIN								90			90

Compared to Portfolio E, the following impacts are observed:

- The 20-year PVRR decreased $37 million to $13.25 billion.
- Although capital cost increased by $20 million and western fuel costs and total emissions increased, reduced market purchases in the west netted an overall benefit.
- Market sales in the west increased slightly.

The addition of baseload CHP in the west as a displacement for a flexible IC Aero unit impacts the optimal system dispatch by reducing generation of gas units at Hermiston as well as the dry cool CCCT and the single IC Aero unit. This outcome is also based on the modeling assumption that the CHP capacity can be counted on as a firm resource. In reality, PacifiCorp provides supplementary and back-up service for similar non-firm generators. Although overall system costs declined with CHP additions, it's a customer driven decision whether or not to add these resources to their sites and effectively lower PacifiCorp's system demand. For this reason, PacifiCorp cannot control the timing or location of CHP additions.

Standby Generators

Within PacifiCorp's service territory, there are large commercial and industrial customers who own standby generators for use during emergency situations. This stress simulates the impact to the preferred supply side portfolio, E, if a substantial number of these customers' standby generators could be dispatched by PacifiCorp to meet peak loads. These generators are most likely diesel-fired units of 1 MW in size or less.

For this stress, 25% of the approximately 300 MW of standby generation in the Utah service area is assumed to be under PacifiCorp's dispatch control in FY 2009. This additional 75 MW of generation delays the need for dry cool CCCT scheduled for 2009 in Portfolio E until 2010. The installation of the coal unit in FY 2011 can also be delayed by one year to FY 2012 while maintaining the 15% planning margin criteria.

In addition to generators in the east, 40 MW of standby generation is added to PacifiCorp's west control area in FY 2013. This 40 MW decreases the need for IC Aero units in the west from two to one unit at 97 MW. Since the units already exist, there are no additional capital costs for these resources except an interconnection cost of $135/kW included with variable O&M and fuel costs. Table 8.38 shows the new Portfolio E with standby generators included.

Table 8.38 – Portfolio E, Modified with Customer Standby Generators

Control Area	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
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
	Standby Generation	East				75							75
West	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								97			97
	Standby Generation	West								40			40

Compared to Portfolio E, the following impacts are observed:

- The 20-year PVRR decreased $60 million to $13.22 billion.
- Capital costs decreased by almost $130 million due to reduction of installed IC Aero units and the delay in the CCCT and pulverized coal units.
- Variable costs increased overall due to decreasing fuel costs and an increase in market purchase reliance.
- Standby generators are dispatched very infrequently due to high O&M.

The standby generators replace the capacity requirement of the displaced IC Aero units but have much lower capacity factors due to very high dispatch costs. Although this portfolio has lower overall costs than Portfolio E, environmental restrictions attributable to local air quality constraints make large scale dispatch of standby diesel generators impractical at this time.

SUMMARY

This chapter documented the process PacifiCorp followed to arrive at the IRP Preferred Portfolio: Portfolio E with Class 1 DSM. The Preferred Portfolio serves as a key building block for development of the IRP Action Plan discussed in the next chapter.

The Preferred Portfolio consists of a balanced mix of fuel-type resource additions, and ranks at or near the top of most stochastic risk measures considered. Furthermore, it also doesn’t stand out as a risky portfolio in terms of the CO_2 cost and High Gas Cost Scenario risks. Finally, it ranks among the lowest of all candidate portfolios in terms of deterministic and stochastic average PVRR.

This chapter also presented the results of portfolio stress case simulations. These simulations focused on the cost impacts of the Planning Margin level, substitution of the “Front Office Transactions” proxy resources with build-or-buy assets, using IGCC technology for the first coal resource, and inclusion of Distributed Generation resources in the resource mix. The results will help inform the IRP Action Plan and future resource procurement activities.

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.

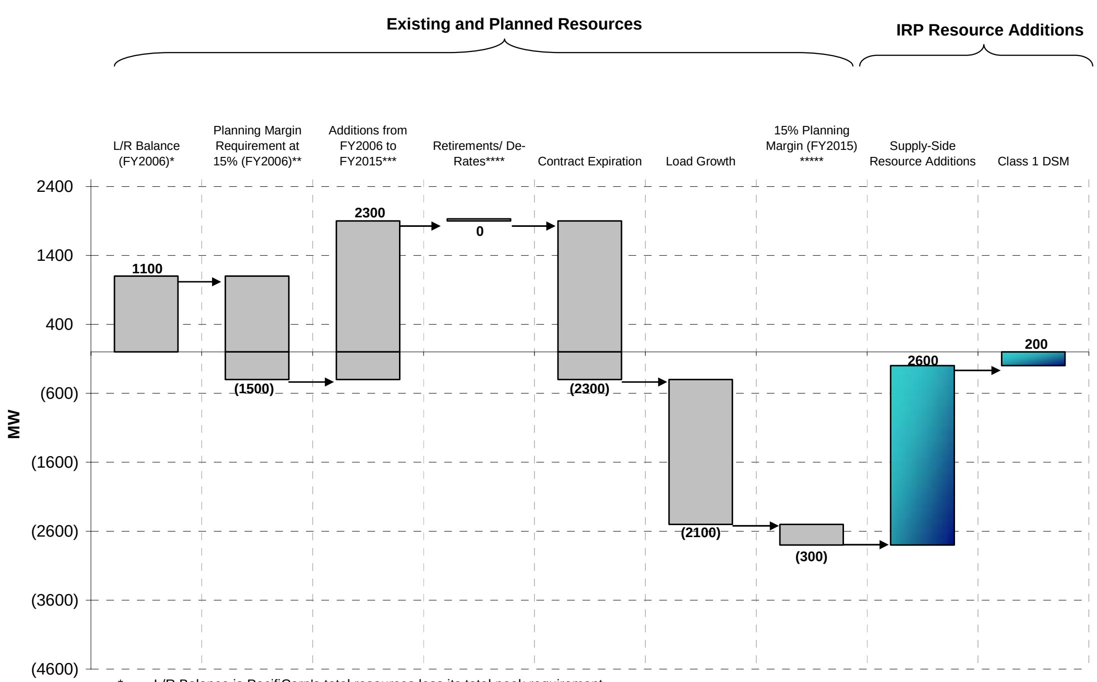
Table 9.1 – Summary of Preferred Portfolio

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.

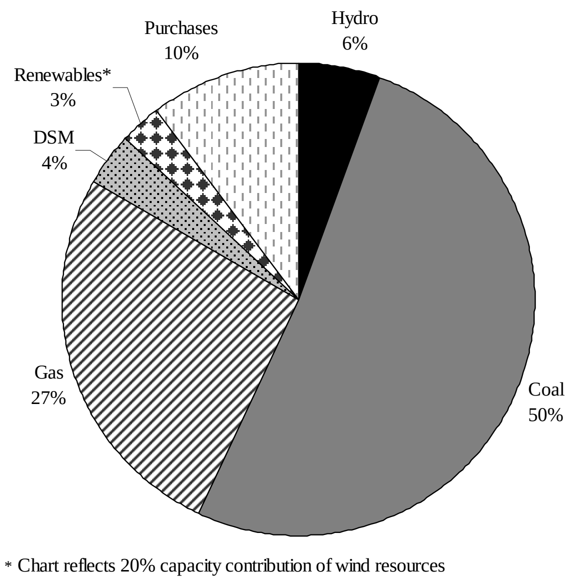
Figure 9.1 – IRP Capacity Requirement Breakdown –Rounded to the Nearest 100 MWs



* 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



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.

<u>Class 1 DSM Procurement</u>

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

<u>Class 2 DSM Procurement</u>

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]

Common Features of Supply Side RFP's

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.

Inability to Procure Designated Resources

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.