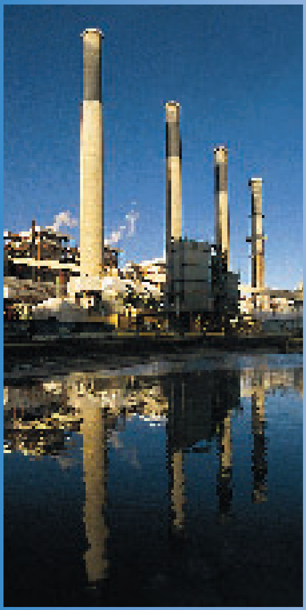

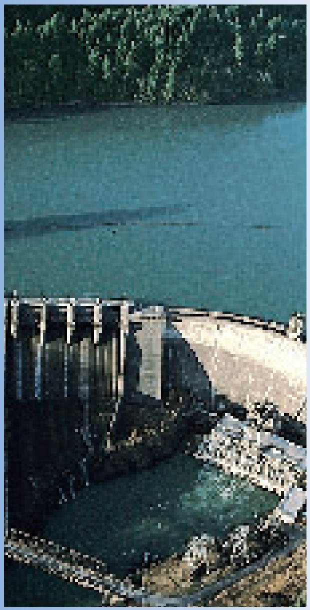

Technical Appendix for the Integrated Resource Plan 2004

Assuring a bright future for our customers

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

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APPENDIX A – ELECTRIC INDUSTRY BACKGROUND

PacifiCorp operates its utility system in a complex institutional environment. This appendix summarizes key features of federal and state law and regulation that constrain or shape this institutional environment. Western energy market conditions are also reviewed, including factors affecting future fuel supplies and prices.

FEDERAL ACTIVITY

Federal Power Act of 1935

The Federal Power Act (FPA) of 1935 established the guidelines for federal regulation of public utilities engaging in interstate commerce of electricity. Through this act, the Federal Power Commission (FPC) was given wider authority, including the ability to:

- Issue licenses for new hydroelectric generation projects,
- Collect utility operational and financial data, including original investment costs and electric generation and sales data, and
- Review electric rates charged by utilities and establish their depreciation schedules.

One of the most important implications of the FPA was the requirement for utilities to charge "fair and reasonable rates." By forcing utilities to publish all rate schedules for public and government review, the FPA required utilities to defend all rates on a cost of service basis. Charging different rates among customers became illegal, absent substantial cost justification. Further, the FPA established the allowable time frame for utilities to change rate schedules.

The FPA of 1935 also outlined strict conflict of interest rules for officers and directors of public utilities engaging in interstate commerce. The FPC was terminated in 1950 when its powers were transferred to the Federal Energy Regulatory Commission (FERC). Later, the United States Department of Energy assumed some of FERC's powers.

Holding Company Act of 1935

Also passed in 1935 was the Public Utilities Holding Company Act (PUHCA). Designed to work in tandem with the FPA of 1935, PUHCA sounded the death knell for multi-tiered holding company structures (described below) that had prevented effective regulation of public utilities, and put utilities operating in more than one state under heavy regulation by the Securities Exchange Commission (SEC). As a result of PUHCA, most utilities operate within a single state (or in multiple states with a contiguous service territory), which allows them exemption from much of the oversight applied by the SEC.

Prior to this legislation, the United States electricity industry had experienced significant consolidation, to the extent that only three companies controlled 45% of the United States electricity market. While many states had public utility commissions, none of these agencies had significant regulatory power, especially when pitted against companies involved in commerce across state lines. Because of the lack of regulatory oversight, holding companies buffered themselves from government regulation by separating from their operating subsidiaries through multiple layers of holding companies, aligned through intentionally complex affiliate relationships. The result was that a few holding companies enjoyed substantial market power and could not be held accountable for engaging in collusive pricing strategies. For example, parent holding companies often charged exorbitant construction rates to their electric companies, which in turn passed on the expenses to consumers. The Federal Trade Commission issued a report in 1928 that listed the abusive practices of holding companies. It concluded that the holding company structure was unsound and "frequently a menace to the investor or the consumer or both."

Further, by being able to hide debt through the multiple levels of holding companies, utilities were able to carry extremely high debt ratios that eventually caused their demise after the stock market crash of 1929. Unable to service their debt, 53 holding companies with combined securities of $1.7 billion went into bankruptcy.

PUHCA and the FPA of 1935 were a direct result of negotiations between utility holding companies and the federal government that began after publication of the Federal Trade Commission's report. Utility owners agreed to provide reliable service at a regulated rate in exchange for an exclusive service territory. Rate regulation would be the responsibility of the Federal Power Commission as established under the FPA of 1935, while the majority of inter-company financial transactions would be regulated by the SEC as outlined in PUHCA. Also, PUHCA dismantled the multi-tiered holding company structure by making it illegal to be more than twice removed from operating subsidiaries.

As a result of PUHCA, more than a third of holding companies owning electricity and natural gas distribution utilities were forced by the SEC to divest such that their electricity and gas services were no longer affiliated. Sections 3(a)(1) and 3(a)(2) allow exemption from PUHCA if the holding companies operate in a single state or within contiguous states. While most holding companies chose to operate so as to qualify for PUHCA exemption, state public utility or public service commissions still strictly regulate these firms.

PURPA – 1978

The Public Utilities Regulatory Policy Act is one of five bills signed into law on November 9, 1978, as part of the National Energy Act. It is the only one remaining in force. Enacted to combat the "energy crisis," and the perceived shortage of petroleum and natural gas, PURPA requires utilities to buy electricity from non-utility generating facilities that use renewable energy sources or "cogeneration," i.e., use steam both for heat and to generate electricity. A non-utility generating facility that meets certain ownership, operating and efficiency criteria established by the FERC is known as a Qualifying Facility or QF. The Act stipulates that electric utilities must interconnect with QFs and buy the capacity and energy they offer at the utility's avoided cost.

One of the other bills passed in 1978 was the Fuel Use Act. On the expectation that the United States was soon to run out of natural gas reserves, Congress passed a law that severely limited the amount of natural gas that could be used to generate electricity. Those limitations were removed in the 1980s and in recent years natural gas has been the fuel of choice for new generation in the United States.

Energy Policy Act of 1992

The Energy Policy Act of 1992 (EPACT) opened access to transmission networks and exempted certain non-utilities from the restrictions of the PUHCA. EPACT made it easier for non-utility generators to enter the wholesale market for electricity. While EPACT opened access to transmission networks for purposes of wholesale transactions, the act did not mandate open access for retail load. The act left it up to individual states to determine if they wanted to open access to electricity lines for purposes of retail sales.

The act also created a new category of electricity producers called exempt wholesale generators (EWGs). By exempting them from PUHCA regulation, the law eliminated a major barrier for utility-affiliated and nonaffiliated electricity producers wanting to compete to build new non-rate-based electricity plants. EWGs differ from PURPA QFs in two ways. First, they are not required to meet PURPA's utility ownership, cogeneration or renewable fuels limitations. Second, utilities are not required to purchase electricity from EWGs.

In addition to giving EWGs and QFs access to distant wholesale markets, EPACT provides transmission-dependent utilities (mostly municipals, public utility districts and rural cooperatives) the ability to shop for wholesale electricity supplies, thus releasing them from their dependency on surrounding investor-owned utilities for wholesale electricity requirements. The transmission provisions of EPACT have led to a nationwide open-access electricity transmission grid for wholesale transactions.

FERC Order 888 – 1996

With the passage of EPACT, Congress opened the door to wholesale competition in the electric utility industry by authorizing FERC to establish regulations providing open access to the nation's transmission system. FERC's subsequent rules, issued in April 1996 as Order 888, are designed to increase wholesale competition in the nation's electricity markets, remedy undue discrimination in transmission access and establish standards for stranded cost recovery. A companion ruling, Order 889, requires utilities to establish electronic systems to share information on a non-discriminatory basis about available transmission capacity.

FERC Order 2000 – 1999

In an effort to continue the evolution of competitive wholesale electricity markets, FERC Order 2000, released in December 1999, requested the voluntary formation of regional transmission organizations (RTOs). FERC's review of electricity markets had shown evidence that traditional management of the transmission grid by vertically integrated electric utilities was inadequate to support the efficient and reliable operation necessary to the evolution of competitive markets. FERC concluded that RTOs, independent organizations designed to operate and control regional transmission systems, would be the best way to proceed to protect the public interest and ensure consumers pay the lowest possible price for reliable service.

FERC's voluntary plan is for all transmission-owning entities in the United States to place their transmission facilities under the control of RTOs that will manage operational and reliability issues and eliminate residual discrimination in transmission service.

The fundamental goals, as expressed by FERC in Order 2000, are to:

- Improve efficiencies in transmission grid management,
- Improve grid reliability,
- Remove remaining opportunities for discriminatory practices,
- Improve market performance, and
- Facilitate lighter handed regulation.

To achieve this end, the rule established minimum characteristics and functions for RTOs, a collaborative process for owners and operators of interstate transmission facilities to consider and develop RTOs, a rate-making reform process, and a schedule for utilities to file with FERC to initiate RTO operations.

Order 2000 is designed to create more efficient transmission systems across the United States to support the growing number of regional wholesale electricity markets by reconfiguring the existing patchwork transmission system into consolidated transmission organizations. The planning and cost recovery functions of RTOs may also help to accomplish FERC's goal to spur interest in the investment and construction of transmission assets where needed for reason of reliability or economic efficiency. Finally, Order 2000 also seeks to lower both economic and trade impediments among transmission organizations on a regional basis. Order 2000 reflected FERC's desire that RTOs be voluntary in formation and expressed FERC's intent to accept a variety of possible RTO structures.

FERC –Proposed Rulemaking

Continuing to refine its views on transmission in relation to competitive electricity markets, the FERC issued a Notice of Proposed Rulemaking on Standard Market Design (SMD) and Structure, NOPR RM01-12-000, in July 2002. After receiving extensive comments on the SMD NOPR, FERC did not issue the final regulations it had intended for 2003. Instead, the Commission issued its White Paper – Wholesale Market Platform in April, 2003. The White Paper responded to NOPR comments and laid out a more general and flexible direction for implementing a wholesale market platform. FERC has not yet promulgated a Final Rule implementing the White Paper principles.

The FERC White Paper reaffirmed the Commission's intention to steer the electric industry towards a market-based framework, including the following general principles:

- Regional independent grid operation
- Regional transmission planning process
- Market monitoring and market power mitigation
- Spot markets for real-time energy balancing
- Transparent and efficient congestion management
- Firm transmission rights, and
- Regional resource adequacy.

With regard to regional resource adequacy, the White Paper clarified FERC's intention that regional state committees should develop a consistent approach and level of resource adequacy throughout a region best suited to that region.

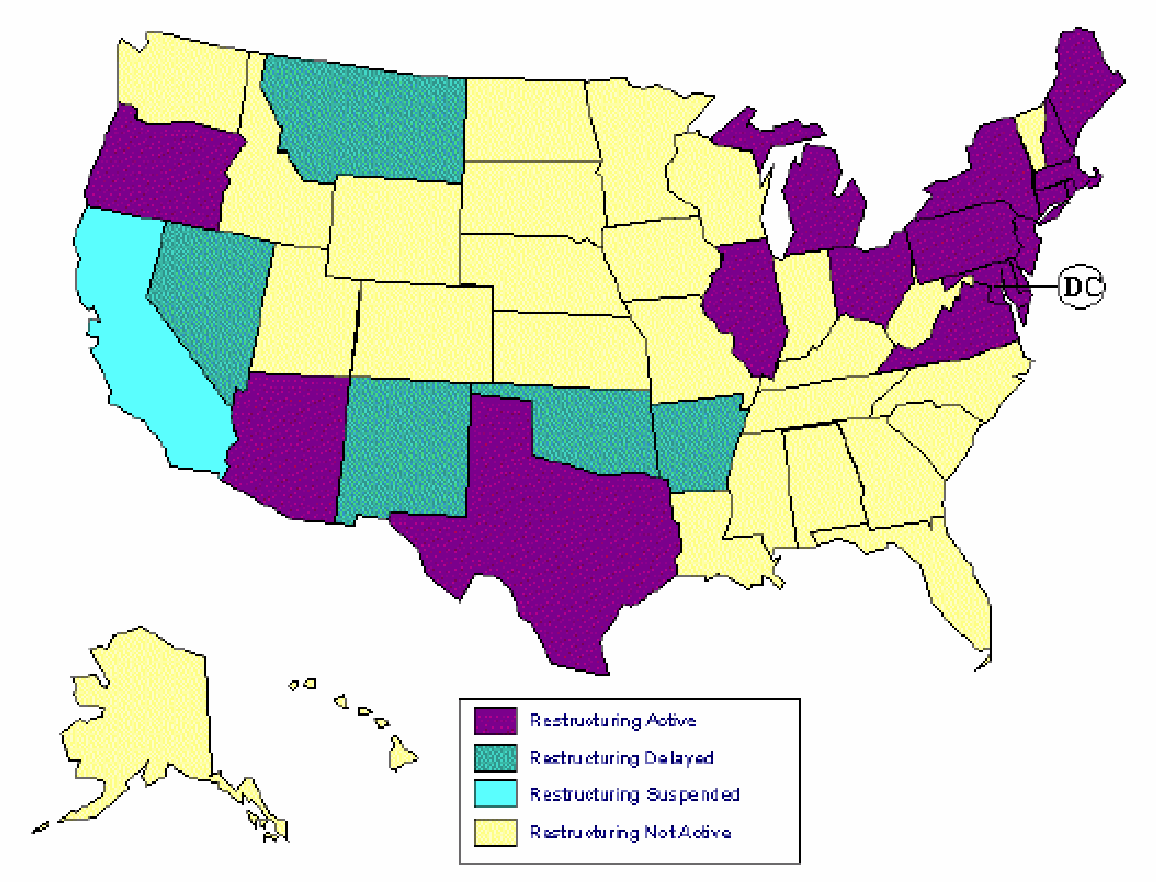
Regional Resource Adequacy

In the absence of a final rule from FERC implementing the Commission's standard market design or White Paper principals, it has been left to state and regional efforts to address resource adequacy requirements. There are currently no WECC-wide requirements for resource adequacy or planning reserves, only operating reserve requirements. In 2004 the California PUC formally adopted a 15-17% planning reserve requirement for load serving entities under its jurisdiction. On a broader regional basis, efforts have been initiated under the auspices of WECC and other regional entities to consider what regional or sub-regional resource adequacy requirements may be appropriate and how they may be implemented. These efforts are described in greater detail in Appendix N. There has been insufficient progress to date from these efforts to provide any definitive guidance to PacifiCorp's IRP.

BRIEF REVIEW OF NATIONAL ACTIVITY REGARDING RETAIL DEREGULATION

Federal legislation has focused on implementation of competition in wholesale electricity markets, while details about retail direct access have been left to the individual states. The restructuring legislation and regulations of the 1990s, particularly the EPACT, have brought about retail-level industry restructuring in several states. The national movement towards a restructured electric utility industry has proceeded at varying paces in different geographic regions. The map in Figure A.1 summarizes the status of state electric restructuring activities as described on the United States Department of Energy – Energy Information Administration web site (http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf).

Figure A.1 – Retail Restructuring



State level restructuring has several common elements: the establishment of retail customer choice, a method to allow regulated vertically integrated utilities to be compensated for investments made in existing generation which may not be recoverable in competitive markets (known as "stranded costs"), and the functional separation of the regulated utilities into separate generation, transmission, distribution and retail service provider business units. There are many differences in the approach to retail restructuring.

California Experience

The California experience is singled out in this report because it has proven to be a case study on how not to approach the transition from regulated bundled electric service to unbundled retail competition. The legislation that introduced electricity industry restructuring in California was Assembly Bill 1890. AB 1890 promised to achieve a number of goals for California energy consumers, including lower electricity bills and choice of generation providers. A key to realizing these goals was a continued adequate supply of electricity. Unfortunately, the Western U.S. ran into a severe shortage of electricity before California completed the transition to its fully deregulated state. This caused disastrous problems for California and the entire Western Interconnect, as described in Chapter 1. Some of the key aspects that created these problems were:

- Lack of new resources
- Large quantity of spot market power exposure by California's private utilities
- Retail rates frozen for California's private utilities
- Deregulated wholesale electricity prices
- Severe drought in WECC resulting in reduced hydroelectric generation

In September of 2001 the California PUC suspended retail choice. The CPUC estimated then that about 2,300 MW of the state's peak load of 46,000 MW was under direct access contracts, mostly with large industrial customers. Contracts in place were allowed to continue until their expiration.

Oregon

Oregon enacted legislation (SB 1149 and HB 3633) to initiate retail choice for all customers, except residential, by March 1, 2002. Starting March 1, 2002, residential customers had the ability to purchase electricity from a portfolio of rate options.

Non-residential customers have the choice each November to elect for the next calendar year whether to continue on PacifiCorp Cost of Service rate. If they elect to opt out of Cost of Service, they may take service from PacifiCorp priced at Market or take service from an Energy Service Supplier (ESS). During 2002 - 2004, approximately 2 - 3 MWa of load took service at the market rate; none took service from an ESS. In the November 2004 window, about 25 average MW of load opted out of Cost of Service. It is expected that the majority of this load will be served by an ESS in 2005.

Larger non-residential customers also have the choice during the twelve-month period ending June 30, 2005, to leave the Cost of Service rate and be served by an ESS for a period up to three years. To date no customer has selected this option.

Other State Activity

The problems experienced in California are causing other states to slow retail direct access in order to re-examine at their retail level restructuring plans in hope of avoiding similar outcomes. According to the EIA, six states have suspended or delayed restructuring activities and about half the 50 states are not actively undertaking restructuring at this time.

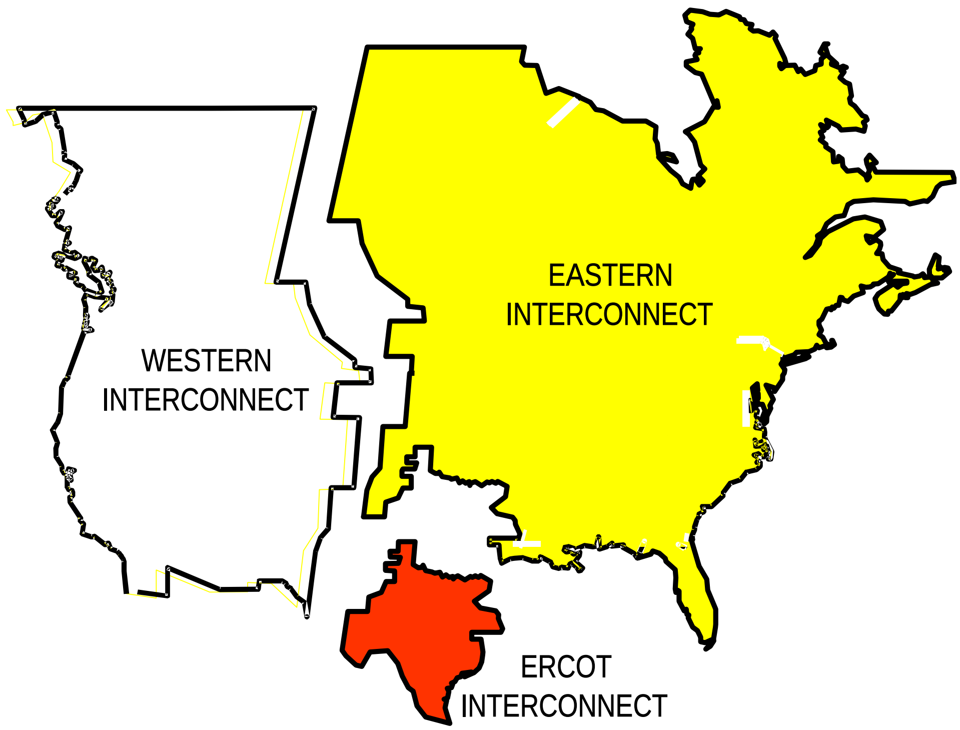
OVERVIEW OF WESTERN ELECTRICITY MARKETS

The Western Interconnect

The Western Interconnect is one of three synchronized electric grids in North America, which are essentially separated from each other[1]. (see Figure A.2).

[1] There are limited interconnections between the three grids by limited capacity direct current transmission facilities.

Figure A.2 – Transmission System Interconnections for the United States and Canada



Each of the three regional interconnects operate electrically as a synchronized, single grid. The nature of this interconnection provides for robust wholesale electricity market transactions among the utilities (such as PacifiCorp) that operate within the interconnected grid. These electricity transactions are a mixture of long-term contracts, seasonal contracts, day-ahead (spot) transactions, and "real-time" transactions. In addition, a number of financial transactions are offered within the each regional interconnect, such as swaps under which a buyer exchanges volatile spot market prices for fixed prices.

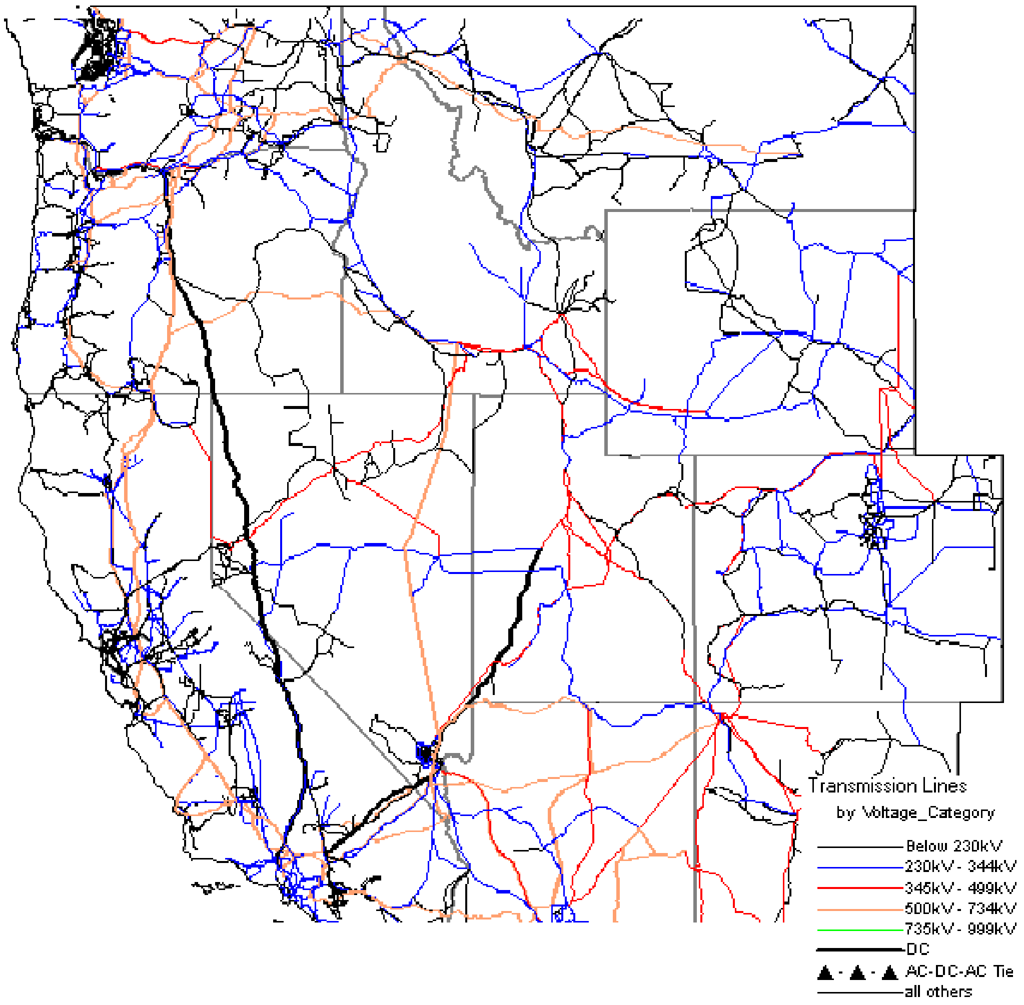
For the Western Interconnect, the Western Electricity Coordinating Council (WECC), organized in August 1967, provides coordination in operating and planning a reliable and adequate electricity system for the Western Interconnect. Geographically, the WECC is the largest of the regional councils of the North American Electric Reliability Council (NERC). WECC covers most of 11 western states, two Canadian provinces, and a small part of Northwestern Mexico.

<u>Electric Transmission in Western Interconnect</u>

The Western interconnection is made up of a vast high voltage transmission grid that allows movement of electricity in a flexible manner. While there is good ability to move electricity to and from many areas of the interconnect, at times there may be the desire to move more electricity than the transmission grid can handle. Path ratings and electricity flows are provided by the WECC to avoid such congestion, and myriad contractual arrangements govern who has the right to use the capability of the transmission system.

Figure A.3 shows the major transmission lines that make up the WECC interconnected grid.

Figure A.3 – Major Transmission lines in WECC



__The Load/Resource Balance In West__

The actual peak load in WECC in the summer of 2003 was 139,914 MW and 136,108 MW in the summer of 2002. Peak load in the summer of 2000 was 130,892 MW and 125,040 MW in the summer of 2001. Peak load in the summer of 2001 was significantly reduced as a result of demand response to the recent electricity crisis in WECC and slowdown in economic activity attendant to a recession but has since recovered to growth rates more representative of long-term trend.

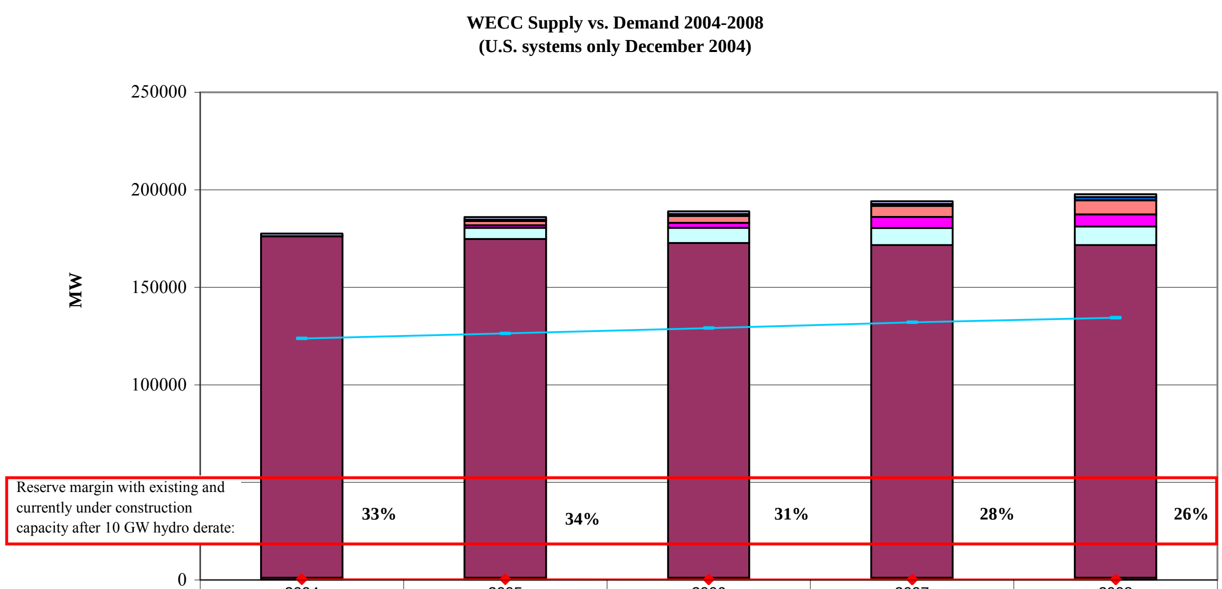
There is approximately 186,000 MW of installed generating capacity in WECC in 2004. About 63,000 MW of this total is hydroelectric capacity. Total installed hydroelectric capacity cannot be fully relied upon for meeting peak loads across all heavy load hours because of limited reservoir storage.

The WECC load/resource balance has undergone rapid change with a wave of new generation since 2001. Additions totaling 15,896 MW reached commercial operation during 2001 and 2002. New capacity in operation in 2003 and 2004 totals 15,723 MW. An additional 7,292 MW is under construction with commercial operation expected by 2006. Offsetting these additions were retirements of 2,907 MW of older generation between 2001 and 2004.

California and Arizona lead other states in these capacity additions by a wide margin. California added 10,196 MW between 2001 and year-end 2004 and Arizona added 10,541 MW in that time period. The vast majority of capacity currently under construction (7,398 of 8,896 MW) is combined cycle. The combined cycle and combined cycle/cogeneration capacity categories also dominate generation put into service since January 2001, at 23,059 MW out of 31,620 MW.

The near-term effect of this wave of capacity additions is that aggregate WECC reserve margins have recovered from the margins that contributed to the 2000-2001 electricity crisis. Figure A.4 illustrates existing and new generation in relation to projected peak demand for the United States portions of the WECC. These data support the conclusion that existing capacity and current construction will yield adequate WECC reserve margins in aggregate at least through 2008.

Figure A.4 – WECC Existing and New Generation versus Demand



	2004	2005	2006	2007	2008
Self Gen	1364	1364	1364	1364	1364
Proposed	0	654	985	1008	1765
Early Dev	0	2174	3576	5630	7132
Adv Dev	4	1311	2397	5702	6352
Under Constr	66	5797	7887	8802	9440
Net Operating	174995	173549	171531	170480	170480
Standby	1172	1172	1172	1172	1172
Platts Peak	123702	126311	129115	132009	134421
Net Exchange	328	328	256	246	244

Figure A.4 illustrates projected reserve margins under expected conditions for U.S. systems of the WECC. Similar results and conclusions hold for the entire WECC and for most sub-areas of the WECC[2]. Projecting reserves into the distant future is not a precise exercise, giving uncertainties on both the supply and demand side. For example, the WECC publishes Power Supply Assessments[3] which estimate planning reserves under a range of future scenarios in which demand exceeding forecasts and addition of uncommitted resources are the primary variables. The Assessment cautions that, beyond a few years, these assessments must be viewed as an indication of future resource needs, rather than a prediction of supply margins.

The above qualification is only reasonable, given that resource additions over and above committed resources are the subject of future decisions. Major changes to market conditions and rules since the 2000-2001 western market crisis, however, provide assurance that a return of those conditions is highly unlikely. Chapter 1 of this IRP lists a number of market structure reforms that facilitate ongoing capacity additions in the future and mitigate market dysfunctions that occurred in the past. Moreover, the large wave of capacity additions already accomplished in the Western Interconnect have been accompanied by a wave of new generating projects at various stages of development that can be brought into service to meet future capacity needs. Currently, construction has been suspended on approximately 3700 MW of generating capacity until market conditions or capacity needs warrant, and additional projects totaling 3400 MW of capacity are in advanced development, having obtained all necessary permits[4]. Together these provide a backlog of new generation that can be readily deployed to avoid a repeat of the inadequate reserve margins experienced in 2000-2001.

Natural Gas Market Overview

Natural gas plays an important role in electricity markets in the West. With recent additions, gas fired capacity makes up about 38% of total WECC capacity. Natural gas-fired resources are on the margin and setting wholesale spot price during most hours of the year. Indeed, during 2003 and 2004 Western power markets have demonstrated a strong sensitivity to higher and increasingly volatile natural gas prices. The high and volatile gas prices over this period reflect current tight conditions in North American natural gas markets. Some of the conditions supporting higher prices should be seen as transitory, while others reflect an ongoing shift in supply and demand that have inexorably and permanently raised hydrocarbon fuel prices to levels above those experienced in the last decade.

Consideration of natural gas as a fuel for new generating plants must deal with two related questions. First, can natural gas fired generating plants be reasonably assured of adequate fuel supplies over their economic life? Second, what is the expected future price of natural gas and the degree of uncertainty surrounding that price? These two questions necessarily touch on the North American gas market as a whole, and increasingly with a global market as liquefied natural gas (LNG) emerges as a global commodity and significant source of North American supply.

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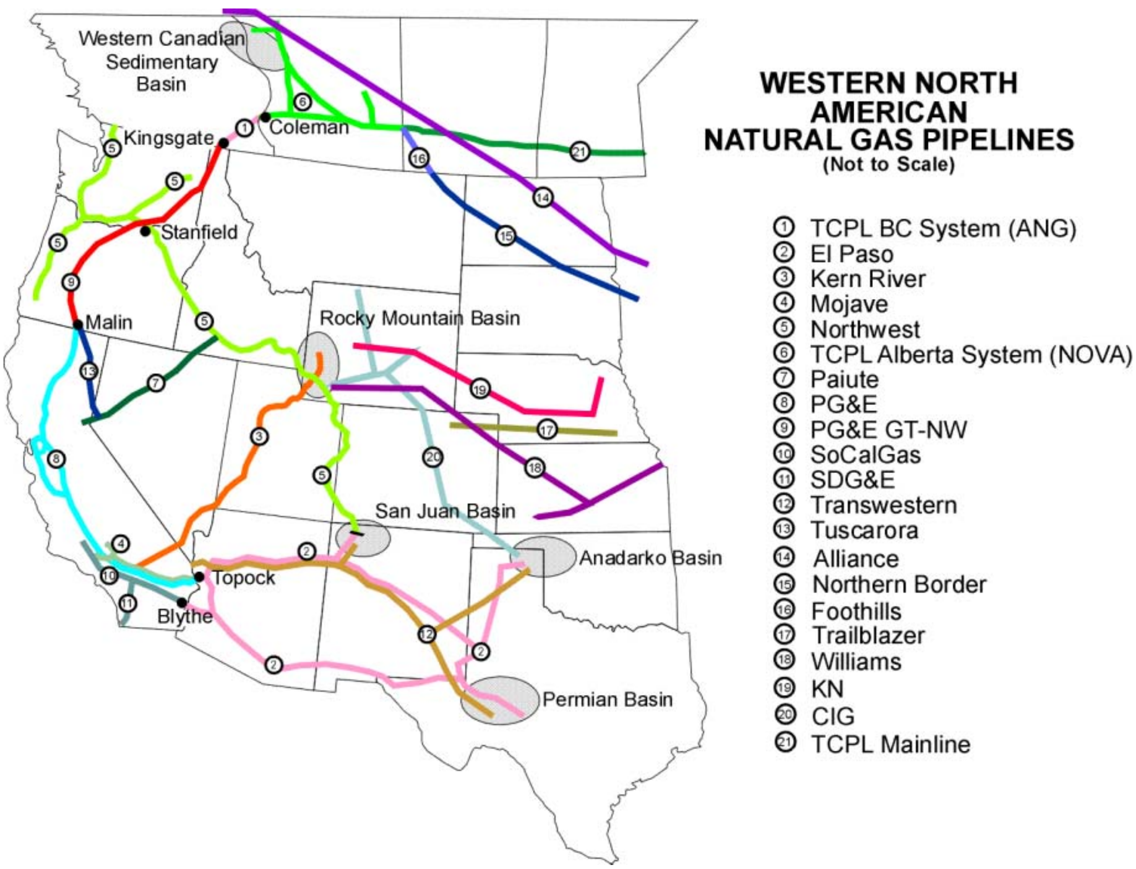
[2] WECC, *10-Year Coordinated Plan Summary*, September 2004. Those results show projected margins exceed planning reserves for each of the four WECC sub-areas at least through 2008 when considering expected conditions. If only committed (i.e. under construction) resources are considered, planning reserves are expected through 2008 in with the CA-MX sub-area through 2006 being the exception.
[3] WECC, *Power Supply Assessment*, November 24, 2004.
[4] Platts NewGen Data Base, November, 2004.

The North American natural gas market has grown increasingly geographically integrated through extensive pipeline and storage infrastructure, a trend that is expected to continue. This means that natural gas prices in different regions of North America will remain well connected and move in parallel, although occasional temporary regional disparities will emerge when supply or demand excursions from trends are constrained by pipeline infrastructure. Natural gas pipelines are relatively easy to permit and build in the relatively unpopulated areas of the West. A large number of pipeline expansions or new pipelines are proposed. Figure A.5 shows the major gas supply basins and gas pipelines in the West.

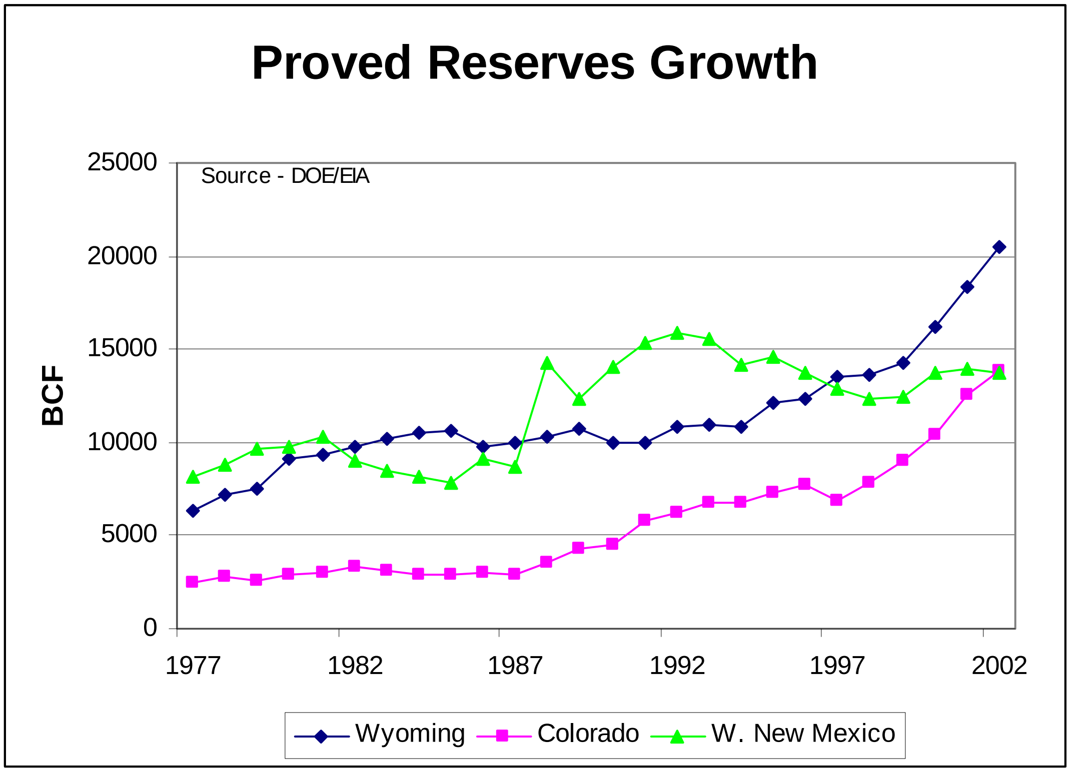
Figure A.5 – Major Gas Pipelines and Supply Basins



A distinguishing feature of natural gas is the dynamic and relatively short life of gas reserves, especially in contrast to U.S. coal reserves. Proven reserves of natural gas in the U.S. represent only about ten years of life at current production rates, while coal reserves are sufficient to supply about 250 years at current production rates. While this raises the question of adequacy of natural gas reserves to supply new gas generation with plant lives of 30 or more years, there are ample data to suggest that adequate fuel supplies exist for new gas fired generation in the WECC.

Specifically in the entire Rocky Mountain region, proved reserves in 2002 totaled 53,144 bcf while production during 2002 totaled 3,713 bcf. The reserves represent about 14 years of supply at current production levels[5]. It is important to recognize, however, that proved reserves are added each year, tending to approximately replace the amount of gas production that was removed from reserves. For example, Wyoming proved reserves grew in 2002 from 18,398 bcf to 20,527, despite the production of 1,388 bcf. In other words, additions to proved reserves totaled 3,517 bcf, more than twice the annual production. Figure A.6 plots proved reserves growth for the three major areas of the Rocky Mountain region[6].

Figure A.6 – Rocky Mountain Region Reserves Growth



Although such large net additions to proved reserves won't necessarily be repeated into the future, experience has shown that annual additions to reserves will continue, supporting continued or growing production. For example, the 2004 Annual Energy Outlook [EIA, January 2004] projects annual Rocky Mountain region production will grow to 4,600 bcf in 2010 and 6,300 bcf by 2025.

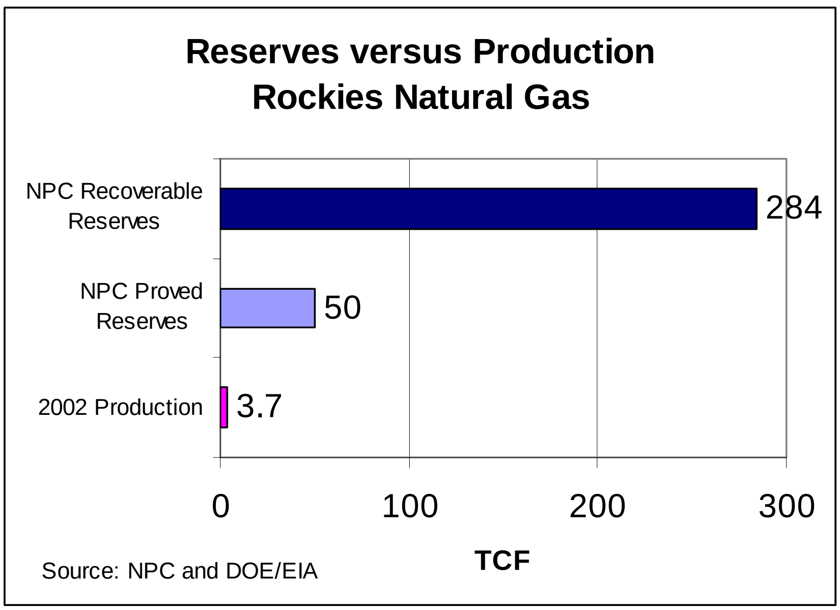
These kinds of projections rely on estimates of technically recoverable resource. While proved reserves represent gas in known and developed reservoirs with demonstrated production potential, geologists also estimate yet-unproved reserves in several categories, using a number of methods. The 2004 Annual Energy Outlook estimates technically recoverable natural gas resources totaling 1,065 tcf for the lower 48 states, compared with 175 tcf of proved reserves. The technically recoverable resource estimate is made up of four pieces, as summarized below.

[5] U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves - 2002 Annual Report, EIA, December 2003
[6] These are from the DOE/EIA web site at http://tonto.eia.doe.gov/dnav/ng/ng_enr_dry_dcu_NUS_a.htm

Undiscovered Nonassociated	222 tcf
Inferred Nonassociated	232 tcf
Unconventional	475 tcf
Associated Dissolved	136 tcf

For the Rocky Mountain region specifically, the undiscovered unconventional resource is estimated at 303 tcf, or about six times current proved reserves, according to the Annual Energy Outlook[7]. Using somewhat different definitions and geographic grouping, the recent National Petroleum Council (NPC) report estimated the technically recoverable resource for the Rockies at 284 tcf[8]. Figure A.7 below graphically compares 2002 production to the NPC estimates of proved reserves and technically recoverable resource for the Rocky Mountain region. The technically recoverable resource is about 77 times the 2002 production rate.

Figure A.7 – Rocky Mountain Reserves Estimates



The NPC report estimated the technically recoverable resource for other regions of North America, as well. It concluded that the traditional sources of gas supply can be relied on to provide a large fraction of future demand in the long run, but that these will need to be supplemented. New large sources such as LNG and Arctic gas were identified as capable of providing the supplemental sources, although these sources face higher costs and different development barriers than the traditional sources.

While natural gas reserves in North America appear to be plentiful, it is generally accepted that production rates are reaching a plateau during this decade and entering a long, gradual decline. The most economical new reserves are in frontier areas such as the arctic North Slope in Alaska and the Mackenzie Delta of Canada. The major challenge in development of these resources for

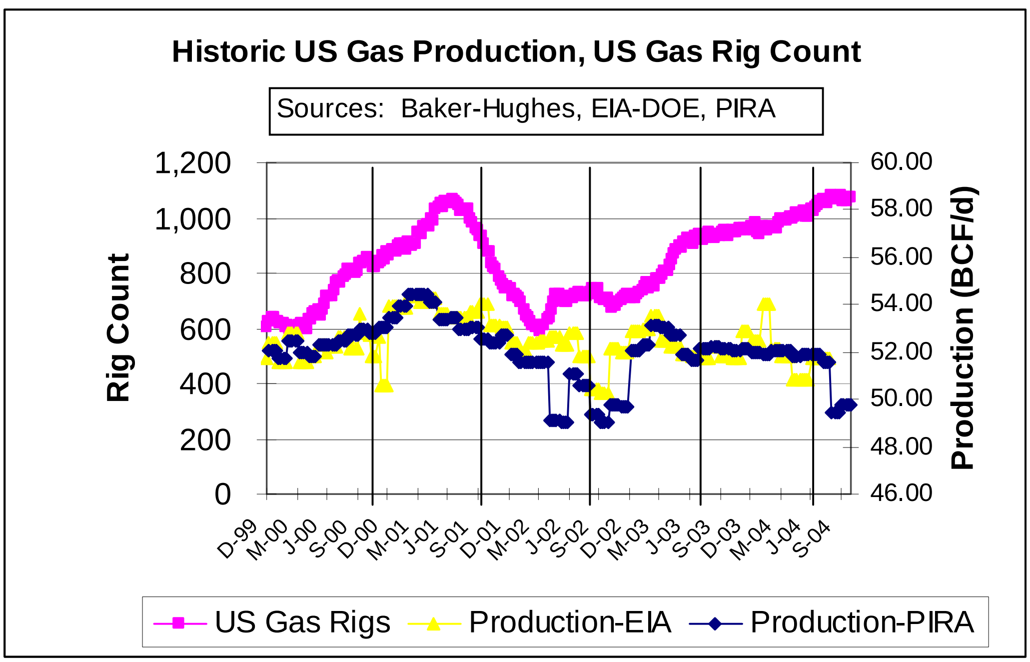
[7] EIA, January 2004, p. 36
[8] Balancing Natural Gas Policy, NPC, September 2003

North American supplies is construction of one or more pipelines to Western Canada and the United States. At present, a Mackenzie Delta pipeline is not expected before 2010, while a pipeline connecting the Alaska North Slope to the lower 48 is not likely to be constructed before 2015.

LNG imports are expected to grow significantly over the next decade as additional receiving terminals are constructed, adding to the current capacity of four such terminals now operating in the US. More than forty new terminals are currently in some stage of proposal or development in North America, although a much smaller number are likely to be completed. Similar infrastructure expansion of liquefaction terminals and LNG tankers is also underway. These trends support forecasts for growth in LNG imports from an estimated 1.6 bcf/day in 2004 to between 9 and 14 bcf/day by 2015. By comparison, domestic US gas production has averaged about 52 bcf/day over the last five years.

The cost of natural gas production has increased significantly in mature North American regions. Recent estimates of average finding, development, production and transportation costs for the Gulf Coast area are between \$3 and \$4/MMBtu for gas delivered on-shore in 2003[9]. These will inevitably grow both with inflation and in real terms. This conclusion is also supported by the recent trend of stagnant domestic production in the face of record drilling rates, as illustrated in Figure A.8. While gas production has historically trended up with increases in operating rigs, this has not been the case since the most recent upswing in U.S. gas oriented rig numbers beginning in early 2002.

Figure A.8 – Gas Production and Rig Count



[9] Source – *Bottom Line – A New Long-term Floor for North American Gas Prices*, CERA Private Report, September 2004

LNG imports in the long run are not believed to be limited by the size of global reserves, which are huge, but by the required infrastructure to deliver LNG from remote sources. The full cost of LNG delivered to U.S. pipelines is estimated to be in the range of $2.50 to $4.00/MMBtu (real 2004$)[10]. Since this is likely to be below the full cost of marginal domestic supplies, it will be these costs rather than LNG costs that tend to set price in the long run.

Coal Overview for West

As of 2004, coal fired generation accounted for about 20% of installed capacity in the Western Interconnect. Since 2000, however, about 97% of new generating capacity in the West has been natural gas fueled. High and volatile natural gas prices in recent years have resulted in renewed interest in coal-fired generation, and currently there are 530 MW of coal fired generation under construction in the Western interconnect, with more than 14,000 MW proposed or in various stages of development.

While coal-fired generation has higher capital cost and longer construction lead-times, coal fuel operating costs can be much lower than the operating cost of a natural gas generator. This is especially true if the coal plant can be built near the coal reserve, thus avoiding the need to transport the coal great distances. Further, coal costs are historically less volatile than natural gas costs. In addition, a specific coal resource and mine can be developed in association with a new or existing generating plant. In this fashion, a large fraction of a plant's fuel requirement (if not the entire requirement over the plant's life), can be acquired with minimal supply or cost uncertainty. This is in contrast to natural gas resources, since the life and production from a particular well or reserve is relatively short and often unpredictable.

Vast reserves of coal in North America are available to fuel existing and potential new coal fired generation. There are 268 billion short tons of estimated recoverable reserves of coal in the U.S., or about 250 years worth of coal at the 2003 production rate of 1,072 million short tons[11]. Table A.1 below illustrates the relative abundance of coal, both in reserves and current production, from the five Rocky Mountain States of Colorado, Montana, New Mexico, Utah and Wyoming.

Table A.1 – Western Coal Production and Reserves

		(million short tons)		
	Production - 2003	**Recoverable Reserves at Producing Mines**	**Estimated Recoverable Reserves**	**Demonstrated Recoverable Reserves**
Colorado	35.8	427	9,837	16,365
Montana	37.0	1,197	75,030	119,330
New Mexico	26.3	1,351	6,958	12,212
Utah	23.1	331	2,771	5,488
Wyoming	376.3	6,707	42,232	64,821
Total US	1,071	17,955	268,396	496,092

Source: Annual Coal Report 2003, EIA

[10] Ibid.
[11] Energy Information Administration, DOE, *Annual Coal Report 2003*.

While almost 500 million short tons of coal were produced in the five Rocky Mountain States in 2003, most of that was exported, with only 116 million short tons consumed in power generation in all eight Mountain States. The ratio of production to reserves from operating mines in each of these states indicates that new reserves and mines will need to be developed to meet long term requirements of existing and proposed new coal fired generation in the West. Access to reserves could, in some cases, constrain the ultimate development of new coal supplies. For example, establishment of the Grand Staircase – Escalante National Monument in 1996 is estimated to have removed about 11 billion short tons of economically recoverable coal from the base of reserves in Utah[12].

While it is clear that vast reserves of coal are present in Rocky Mountain States, care must still be exercised in assessing the potential for and economics of new coal fired generation, given the issues of access to reserves and the sensitivity of coal costs to transportation requirements. In addition, since coal reserves are typically not located close to large metropolitan areas (i.e., where the large blocks of retail load are located), it becomes necessary to carefully assess the capability of the transmission grid to move the electricity from a new coal-fired generating plant to the load it will be serving.

OVERVIEW OF THE PACIFIC NORTHWEST AREA OF THE WESTERN INTERCONNECT

The Pacific Northwest (PNW) is a subset of the WECC. WECC defines the PNW in two different fashions. The larger PNW includes British Columbia and Alberta, Canada. The United States portion of the PNW excludes them. The Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501, December 5, 1980) defines the Pacific Northwest as the area consisting of Oregon, Washington and Idaho; the portion of Montana west of the Continental Divide; the portions of Nevada, Utah and Wyoming that are within the Columbia River drainage basin; and any contiguous areas not in excess of 75 air miles from the area referred to above that are a part of the service area of a rural electric cooperative customer served by the BPA administrator on December 5, 1980, that has a distribution system from which it serves both within and without such region.

Under this definition, the PacifiCorp service territory in Utah and parts of Wyoming are not located within the PNW.

<u>The Bonneville Power Administration</u>

The Bonneville Project Act (P.L. 75-32, August 20, 1937) was passed to establish the Bonneville Power Administration (BPA) as the entity responsible for delivery and marketing the electricity from federally owned dams in the PNW. Currently, BPA markets the electricity from 30 hydroelectric generation projects and one nuclear plant. BPA has also built and operates a vast electricity transmission grid in the PNW. BPA's transmission system accounts for about three-quarters of the region's high-voltage grid and includes major transmission links with other

[12] Utah Geological Survey, Circular 93, *A Preliminary Assessment of Energy and Mineral Resources within the Grand Staircase - Escalante National Monument*, UTAH DEPARTMENT OF NATURAL RESOURCES, January 1997

regions. As such, PacifiCorp utilizes the BPA transmission system under numerous commercial arrangements (and BPA similarly utilizes PacifiCorp's transmission system).

The Northwest Power Act of 1980

The Pacific Northwest Electric Power Planning and Conservation Act (Act) was passed by Congress in 1980 primarily to resolve debates and litigation in the region regarding who would have access to the Federal Base System (FBS) electricity (primarily federally owned hydroelectric generation facilities) whose output is marketed by the BPA. The Act prescribed the formation of the Northwest Power Planning Council that has eight council members. The members include two governor appointees each from Oregon, Washington, Idaho and Montana. The Act provides for the development of both an electricity plan and a fish and wildlife program for the PNW. Importantly for PacifiCorp, the Act provided for a "Residential Exchange" under which PacifiCorp gets access to FBS electricity for its residential load in the PNW. This access may be in the form of an exchange of higher cost PacifiCorp electricity for lower cost FBS electricity or as a direct sale of FBS electricity. Resulting economic benefits are passed directly to eligible residential and small farm customers served by PacifiCorp.

Effect of Endangered Species Act on Electricity Supply

The Endangered Species Act (ESA) was passed by congress in 1973. ESA has had a profound impact on electricity supply in the Pacific Northwest primarily through its impact on the operation of hydroelectric generation plants. Declining stocks of various species of fish (including several salmon species) have led to an effort to alter hydroelectric generation project operations to protect them. Many of the hydroelectric generation projects in the PNW (including those owned by PacifiCorp) require a FERC-approved license to operate. Either during the re-licensing of these hydroelectric generation projects or via an opening up of an existing license, FERC can require extensive modifications to the physical facilities or operation of the facilities that greatly reduces the electricity value of the project. Many PacifiCorp-owned hydroelectric generation projects are facing these issues.

Federally owned hydroelectric generation projects are not licensed by FERC, but are still subject to the ESA in their design and operation. As a result of listing a number of endangered or threatened species of fish, the National Marine Fisheries Service (NMFS) prepares a biological opinion of whether the operation of the Federal Columbia River Power System (FCRPS) jeopardizes the species and, if so, how the operation of the FCRPS must be altered in order to avoid jeopardy. These NMFS biological opinions have had a significant impact on storage and release of water at the many federal dams in the PNW and on the use of the water (e.g. requirements to spill water rather than running the water through turbines to create electricity). These impacts on the FCRPS impact prices that BPA must charge PacifiCorp for certain electricity purchases, the availability of electricity in WECC, and prices that PacifiCorp will experience in its spot market purchases and sales.

OVERVIEW OF EXISTING AND EMERGING AIR QUALITY REQUIREMENTS

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

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

The centerpiece of the CAA is a series of requirements to ensure that communities meet national ambient air quality standards (NAAQS) set by EPA for several key air pollutants. The primary objective of the NAAQS is to protect human health. Strategies to meet these standards are contained in federally-approved state implementation plans (SIPs) or, where states fail to develop such plans, in Federal Implementation Plans (FIPs) developed by EPA for those states.

The CAA contains numerous other provisions such as the Prevention of Significant Deterioration (PSD) program designed to ensure that areas in compliance with the NAAQS stay that way. In addition, the CAA contains requirements designed to remedy existing and prevent future impairment of visibility in federal class I areas such as national parks and wilderness areas.

The primary emissions of concern for coal-fired plants include: sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM) controlled for both transport and opacity at the stack, and mercury (Hg). Carbon dioxide (CO_2), although not currently a regulated pollutant under federal or applicable state law, is also an issue of growing concern. Present concerns about the environmental impact of SO_2 and NO_X tend to differ between the western and eastern parts of the United States, with SO_2 being the most significant concern in the west, while NO_X is of greater concern in the east due to its contribution to widespread non-attainment of the NAAQS for ozone. The different air quality issues in the East versus the West are affirmed in recent policy developments (e.g., multi-pollutant legislation and EPA's Clean Air Interstate Rule).

Coal-fired plants nationally and regionally face emissions reduction challenges due to a number of specific regulatory tools used by both government and private citizen groups to require further emission reductions. These methods include: (1) the New Source Review (NSR) enforcement initiative (see explanation below); (2) visibility requirements; (3) ongoing compliance issues; (4) emerging new emission requirements, including new legislation; and (5) changing federal, state and public attitudes, including an increase in lawsuits by citizen groups to achieve emissions reductions.

New Source Review (NSR)

The most pressing regulatory tool that has the potential to force emissions reductions in the near term is the NSR program and the recent NSR enforcement initiative. EPA has attempted to use this enforcement initiative as a means to obtain emission reductions from coal fired power plants through a broader interpretation of NSR applicability. Enforcement activities have included Notices of Violations (NOVs), civil complaints and similar actions against several utilities and one federal agency (TVA) in the eastern US along with the investigation of most major coal plants across the country, including all PacifiCorp plants. As a general matter, the utility industry has vigorously opposed EPA's use of the NSR program as a means of forcing widespread emissions reductions from coal-fired electric generating units.

The NSR program in general requires plant owners or operators to undertake new source review and obtain a preconstruction permit if they propose to build new generating units or modify existing units in a way that increases emissions of regulated pollutants above stated thresholds. Exemptions from the requirement to undergo new source review and obtain a permit include changes that are routine maintenance, repair or replacement (RMRR) and emissions increases resulting from fuel changes or increased hours of operation.

It is the application of NSR to existing units that generated recent controversy. NSR rules for many years were interpreted so that most power plant maintenance and replacement projects did not trigger NSR. In the late 1990s, the NSR rules were reinterpreted to say that NSR applied when all but the most minor maintenance was performed. This reinterpretation of the NSR rules in the enforcement context has created substantial legal controversy and uncertainty and is a major issue for owners of coal-fired electric generating facilities, which require routine maintenance and part replacement in order to operate in a dependable and efficient manner. This application of the NSR rules leaves utilities with little choice – they can either (a) not properly maintain facilities and retire or replace them as they deteriorate, or (b) fully maintain the facilities, with required upgrade of pollution control equipment.

Most of the major utilities in the U.S., including PacifiCorp, have received Section 114 information requests from EPA. The agency uses information acquired through the Section 114 process to determine whether an NSR enforcement action is warranted. Several utilities have been or are now the target of civil enforcement proceedings initiated by EPA and the Department of Justice (DOJ). Six eastern utilities have elected to settle and others have elected to fight enforcement proceedings. EPA and DOJ currently have numerous utility cases in active litigation. Parties to some of these litigation cases are in active settlement discussions and some non-litigation cases are in settlement discussions as well. PacifiCorp is not the subject of civil enforcement proceedings at this time.

Eastern NSR settlements have required the installation of selective catalytic reduction (SCR) technology for NO_X control on approximately sixty percent of system megawatts. PacifiCorp believes that combustion controls are the appropriate control technology choice for coal fired plants in the west, where air quality is excellent. It is not known at this time whether a different western NSR settlement template will develop.

Two key court decisions on NSR have been rendered to date, but with contradictory rulings – one favoring the EPA position and the other favoring the utility position. Thus the key legal issues surrounding NSR remain unsettled. These issues include: (i) the legal meaning of RMRR; (ii) the formula for measuring post-change emissions increases; (iii) factual matters relating to the nature of plant projects; and (iv) the proper remedies for NSR violations.

Additional judicial decisions on enforcement-related issues are imminent and outcomes that favor EPA's reinterpretation of the NSR requirements will likely result in additional controls and penalties for affected utility sources.

Class I Area Visibility Impacts

The Clean Air Act also contains provisions to improve visibility at Class I areas by requiring emissions reductions to reduce regional haze. These requirements, contained in §169A and §169B of the Clean Air Act, are intended to address visibility concerns at Class I areas. The states of Utah and Wyoming have embraced the SO_2 reduction targets developed by the Western Regional Air Partnership (WRAP). The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the U.S. EPA's regional haze regulations. Emissions reduction targets for NO_X are currently under development and the company expects that reductions in both SO_2 and NO_X emissions will be required in order to meet WRAP targets. Additionally, sources demonstrated to have a unique impact on visibility in class I areas may be subject to additional emissions reduction requirements. Over the past 10 years several sources have been involved in negotiations to address their demonstrated or alleged unique contribution to visibility impairment in class I areas.

EPA Proposed Rulemakings

Power plant emissions reductions will also be required as a result of proposed EPA rulemakings under the Clean Air Act. On January 30, 2004 EPA proposed the Interstate Air Quality Rule, later renamed the Clean Air Interstate Rule, and the Utility Mercury Reductions Rule. The Clean Air Interstate Rule would reduce emissions of SO_2 and NO_X from states whose emissions are significantly contributing to fine particle and ozone pollution problems in other downwind states. The proposed rule would cover 29 states in the Eastern United States and the District of Columbia. While the current proposal would not affect PacifiCorp plants, the extension of the rule to the western states could potentially result in requirements for significant emissions reductions at PacifiCorp plants.

In its Utility Mercury Reductions Rule, EPA proposed two methods for controlling mercury emissions from power plants. One approach would create a market-based cap and trade program similar to the SO_2 and NO_X allowance trading program contained in the Title IV Acid Rain Program. The second proposal would require power plants to install maximum achievable control technology (MACT) under Section 112 of the Clean Air Act. EPA is under a court-approved consent decree to publish a final rule establishing MACT standards for mercury from coal-fired power plants by March 2005. Power plant operators must comply with the rule by 2008.

Ongoing Compliance Issues and Citizen Group Litigation

As mentioned, operators of coal-fired electric generating units must address a wide variety of substantive and reporting requirements (compliance assurance monitoring, toxic release inventory, Title IV reporting, etc.). Utility operators must engage in ongoing communication with state regulators to ensure that information needed to determine the regulatory compliance of operations is assured.

In addition, the Clean Air Act provides the opportunity for citizen groups with standing to enforce its requirements through the Courts. This is also a continuing concern across the industry as citizen groups attempt to enforce both settled and novel interpretations of CAA requirements.

Multi-pollutant Legislation

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

- President Bush's Clear Skies Act/Global Climate Change Initiatives,
- Clean Power Act (S. 556) introduced by Senator Jeffords (I-Vt.), and
- The Clean Air Planning Act of 2003 (S. 843) introduced by Senators Carper (D-DE), Lincoln Chafee (R-RI), John Breaux (D-LA), and Max Baucus (D-MT).
- The Climate Stewardship Act, sponsored by Senators John McCain (R-AZ) and Joseph Lieberman (D-CT)

The Administration's Clear Skies Act (H.R. 999 and S. 1844), which was introduced by Reps. Barton (R-TX) and Tauzin (R-LA) and Sens. Inhofe (R-OK) and Voinovich (R-OH), requires reductions for SO_2, NO_X and Hg. Implemented through a tradable allowance program, the emissions caps would be imposed in two phases: 2009 and 2018. The Administration proposal recognizes that the east faces different air quality issues than other parts of the country and will set emission caps to account for these differences. The second Bush Administration proposal (for which no legislation has been introduced) initiates a new voluntary greenhouse gas reduction program. The plan focuses on improving the carbon efficiency of the economy, reducing current emissions of 183 metric tons per million dollars of gross domestic product (GDP) to 151 metric tons per million dollars of GDP by 2012. The Administration's proposal relies on various voluntary programs and incentives to encourage reductions in greenhouse gases from diverse sources, including CO_2 from electric generation.

The Carper bill (S. 843) would regulate SO_2, NO_X, mercury and CO_2 emissions from the electric generating sector: (1) the SO_2 mandate would reduce emissions via three phases to 2.25 million tons in 2015; (2) the 2-phase NO_X program culminates with a 2012 cap of 1.7 million tons; (3) the mercury cap would be in two phases: 2008 and 2012; (4) the two-phase CO_2 program would cap emissions at 2005 levels in 2008 and 2001 levels in 2012.

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

The McCain-Lieberman bill was considered by the US Senate in late 2003 and failed by a 55-43 vote. The legislation would cap emissions of carbon dioxide from US electric generating plants at 2000 levels in 2010. A system of tradable emission allowances would be established as part of the implementation plan.

APPENDIX B – PUBLIC INPUT PROCESS

A critical element of this resource plan is the public input process. PacifiCorp has pursued an open and collaborative approach to involve the Commissions, customers and other stakeholders in PacifiCorp's planning prior to making resource planning decisions. Since these decisions can have significant economic and environmental consequences, conducting the resource plan with transparency and full participation from the Commission and other interested and effected parties is essential.

The public has been involved in this resource plan from its earliest stages and at each decisive step. Participants have both shared comments and ideas and have received information. As reflected in the Report, many of the comments provided by the participants have been adopted by PacifiCorp and have helped contribute to the quality of this resource plan. PacifiCorp will adopt further comments going forward, either as elements of the Action Plan or as future refinements to the planning methodology.

The cornerstone of the public input process has been full-day public input meetings, held approximately every six weeks throughout the year-long plan development period. These meetings have been held jointly in two locations, Salt Lake City and Portland, using telephone and video conferencing technology, to encourage wide participation while minimizing travel burdens and respecting everyone's busy schedules.

The public input meetings were augmented by a series of focused workshops on specific topics, as the need often arose for further detailed discussion among the participants.

PUBLIC INPUT PARTICIPANTS

Among the organizations that were represented and actively involved in this collaborative effort were:

Commissions
- Idaho Public Utilities Commission
- Oregon Public Utilities Commission
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

Interveners
- Citizen's Utility Board of Oregon
- Committee for Consumer Services State of Utah
- Industrial Customers of Northwest Utilities
- Mountain West Consulting, LLC
- Northwest Energy Efficiency Alliance
- NW Energy Coalition
- Oregon Department of Energy

- Renewables Northwest Project
- RES North America
- Salt Lake City
- Salt Lake Community Action Program
- Southwest Energy Efficiency Project
- Sierra Club , Utah Chapter
- Utah Association of Energy Users
- Utah Clean Energy Alliance
- Utah Division of Public Utilities
- Utah Energy Office
- Utah Legislative Watch
- Wasatch Clean Air Coalition
- Western Resource Advocates

Others

- British Columbia Hydro (BC Hydro)
- Portland General Electric (PGE)
- Henwood Consulting (Global Energy Decisions, LLC)
- Shell Oil

PacifiCorp extends its gratitude for the time and energy these participants have given to the plan. Your participation has contributed significantly to the quality of this plan, and your continued participation will help as PacifiCorp strives to improve its planning efforts going forward.

PUBLIC INPUT MEETINGS

PacifiCorp hosted eight full-day public input meetings to discuss various issues including inputs and assumptions, risks, modeling techniques, and analytical results. Below are the agenda's from the public input meetings and the technical workshops.

December 11, 2003

- Market Fundamentals
- Federal & State Activities
  - SB 1149 Update
  - Renewable Energy Policy Update
- Future of Coal
  - Air Quality Update
  - Hunter 4 Update
  - Emerging Coal Technologies
- Transmission
  - Status of RTO West
  - Rocky Mountain Area Transmission Study (RMATS)
- Status of RFP's
  - DSM RFP
  - RFP 2003-A

  - RFP 2004-B - Renewables RFP
- Timeline and Deliverables for 2004 IRP Process

<u>January 29, 2004</u>
- RFP Update
  - RFP 2003A - Supply Side RFP
  - RFP 2003 B – Renewables RFP
  - Demand Side RFP
- Review of Inputs & Assumptions
- Topology Update
- Planning Margin Study
- Review Primen Study Results – Distributed Energy
- Resource Addition Logic

<u>April 23, 2004</u>
- IRP Status and Progress
- FutureGen: IGCC Update
- Renewables RFP 2003 B Update
- 2004 Load Forecast
- Wind Study
- Preliminary L&R
- Planning Margin Study & Portfolio Build Strategies
- Progress on Automatic Resource Addition Logic

<u>June 10, 2004</u>
- 2004 IRP Resource Alternatives
  - Supply Side Resources
  - DSM & Distributed Generation
  - Transmission Alternatives
- Renewable Assumptions (Green Tags, RPS, Product Tax Credit)
- Market Assumptions
- Environmental Adder Assumptions (NO_X, SO_2, Hg, CO_2)
- Henwood Planning Reserve Margin Study
- Load and Resource Balances

<u>July 27, 2004</u>
- Market Price Forecast
- DSM Update
- Update on Planning Margin Study (Bathtub chart)
- Update on Capacity Expansion Model
- Proposed Stress Cases
- Portfolio Development Process
- Treatment of Short Term Contracts in the IRP (Postponed to August 27th)
- Distributed Generation (Postponed to August 27th)

August 27, 2004
- Front Office Transactions in the IRP (From Previous Meeting)
- Distributed Generation (From Previous Meeting)
- Renewable Assumptions for Portfolio Analysis
- Transmission Expansion Scenario
- Results of Initial Portfolio Runs
- Risk Analysis Discussion
- Action Plan Path Analysis

September 30, 2004
- Review of New Portfolios
- Results of Deterministic Runs
- Results of Stochastic Analysis
- Customer Impacts
- DSM Analysis

November 10, 2004
- Update on IGCC
- Renewables Results using CEM
- Updated Results of Stochastic Analysis
- Results of Scenario Analysis
- Supply Side Portfolio Selection
- DSM Analysis
- Review Draft IRP
- Review Action Plan & Path Analysis

PUBLIC TECHNICAL WORKSHOPS

In addition to the public input meetings summarized above, a number of workshops were sponsored over the course of the planning process. These provided workshop participants with a more in-depth discussion on specific topics and technical matters. A summary of the workshops held is provided here:

January 30, 2004 - Load Forecasting
- New Commercial Survey Results
- Changing Commercial Saturations
- Conditional Demand Analysis
- Changing Commercial Electricity Unit Intensity (EUI's)
- Existing Residential Saturations
- Changing Residential Unit Electric Consumption (UEC's)

June 25, 2004 - Load Forecasting Annual Review
- Elasticity Review
- Economic Outlook
- Future meetings

<u>August 26, 2004 – IRP Technical Workshop – Capacity Expansion Model (CEM)</u>

- Capacity Expansion Model
  - Overview
  - Model Scope
  - Model Objective and Constraints
  - Model Variables
- CEM Model Status
  - Overview
  - Model Validation
  - Resource Options
  - Preliminary portfolio
  - Conclusions

<u>November 9, 2004 – IRP Technical Workshop – RMATS Discussion</u>

- RMATS Overview and Modeling
- Scope of RMATS / IRP Comparison
- Assumption Comparison
- New Wyoming Coal / Transmission Expansion Portfolio

PARKING LOT ISSUES

During the course of the public input meetings, certain concerns needed additional explanation from PacifiCorp. In the course of the public input meetings and workshops, questions or issues were often raised which were taken off-line or put in a "parking lot." PacifiCorp either responded in writing in detail to address these parking lot issues, or in many cases, addressed them in a subsequent public input meeting or workshop. PacifiCorp responded to over 50 different complex questions that covered all aspects of the IRP.

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APPENDIX C – BASE ASSUMPTIONS

GENERAL ASSUMPTIONS

Study Period

PacifiCorp operates on a Fiscal Year that begins on April 1st and ends on March 31st. The study period covers a 20-year period beginning April 1, 2005 and ending March 31, 2025. Market simulations cover the entire study period.

Inflation

Where price forecasts and associated escalation rates were not established by external sources, IRP simulations and price forecasts were performed with PacifiCorp's inflation rate schedule (See table C.1 below). Unless otherwise stated, prices or values in this appendix are expressed in nominal dollars.

Table C.1 – Inflation Table

Calendar Year	Annual Rate
2004-2010	2.02%
2011-2020	2.94%
2020-2030	3.48%

Market Size and Characteristics

PacifiCorp adopted the following market assumptions for IRP system simulation purposes:

- External markets are used to support physical balancing needs—which are defined as short-term purchases, sales, and exchanges necessary to match generation with loads—as well as to help lower system net power costs.
- As mentioned in Chapter 3, firm transmission rights constitute the primary market size constraint. Transmission transfer capabilities between transmission areas are initially set based on these firm transmission rights as well as known contractual obligations. Therefore, the capabilities do not reflect the availability or physical capabilities of the lines. (For example, non-firm transmission market opportunities are not accounted for.)
- The transfer capabilities are modified as appropriate to reflect contractual obligations and to model transmission expansion resources.
- PacifiCorp assumes no changes in firm transmission rights throughout the 20-year planning horizon, except those resulting from current contractual obligations and transfer capability made available through modeled transmission resource additions.
- PacifiCorp considers liquid markets where it has direct physical market activity. For the east, the markets represented include Palo Verde (PV) and Four Corners (FC). For the west, the markets represented include Mid-Columbia (MidC) and California Oregon Boarder (COB).

Hourly Operating Margin

The Hourly Operating Margin is based on WECC Operating Reserves to cover Contingency Reserves and Regulating Reserves.

- **Regulating Reserves:** 175 MW to control frequency to ACE tolerance

- **Contingency Reserves:** 5% of control area demand carried by hydro generation and 7% of control area demand carried by thermal units.

Planning Margin

PacifiCorp assumes a 15% planning margin for the 2004 IRP and will continue to review resource adequacy issues when addressing long range planning. See Appendix N, Planning Margin Study, for a detailed review.

FORECASTS

System Load Forecast

The loads for east and west control areas are summarized in table C.2. The load forecast reflects loads growing at an average rate of 2.1% per year. The east system continues to grow faster than the west system, with respective average annual growth rates of 2.7% and 1.1% over the forecast horizon.

Table C.2 – System Load Forecast for PacifiCorp Control Areas

	East			West	
Fiscal Year	Peak	Total GWH		Peak	Total GWH
2006	5,910	36,979		4,288	25,261
2007	6,170	37,655		4,193	25,142
2008	6,418	38,717		4,123	24,138
2009	6,654	39,892		3,501*	21,421
2010	6,895	40,891		3,536	21,645
2011	7,107	41,815		3,569	21,901
2012	7,368	43,053		3,593	22,186
2013	7,596	44,188		3,633	22,477
2014	7,843	45,257		3,707	22,801
2015	8,118	46,432		3,764	23,179
2016	8,359	47,426		3,823	23,530
2017	8,616	48,797		3,863	23,993
2018	8,855	49,894		3,930	24,318
2019	9,130	51,140		3,991	24,691
2020	9,394	52,331		4,039	25,070
2021	9,666	53,604		4,123	25,527
2022	9,966	54,990		4,191	25,923
2023	10,272	56,544		4,248	26,377
2024	10,519	58,018		4,315	26,749
2025	10,900	60,193		4,507	27,540

East: Wyoming, Utah and Idaho
West: California, Oregon and Washington

* The load decrease in the West in FY2009 is a result of the expiration of the Clark Co. PUD contract. (See Contract tables , Table C.9)

See Chapter 3 and Appendix I for information on the application and derivation of the System Load Forecast.

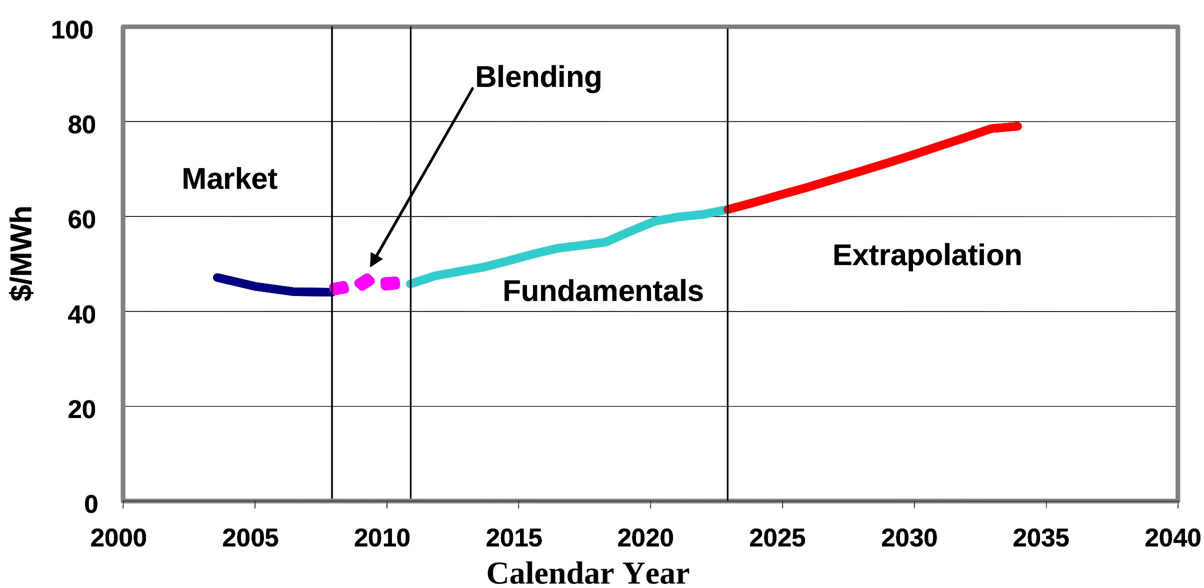
Industrial Customers
This IRP assumes that all of PacifiCorp's existing industrial customers will remain retail customers of PacifiCorp for the life of the plan.

Fuel and Wholesale Electricity Prices

Natural Gas
Figure C.1 summarizes the natural gas and wholesale electric curve methodology used for the fuel cost inputs for portfolio modeling. The resulting natural gas prices, shown graphically in Figure C.2, were developed by blending PacifiCorp's internally-derived, near-term forward price forecasts, dated June 30, 2004, with a long term forecast. The long term forecast (dated May 11, 2004) is derived from forecasts obtained from an independent advisory service, primarily PIRA Energy Group. Prices are shown in nominal dollars. Since the advisory service/PacifiCorp forecast only extends through CY 2015, prices for CY 2016 through CY 2025 were derived by escalating the CY 2015 values using PacifiCorp's inflation rate schedule.

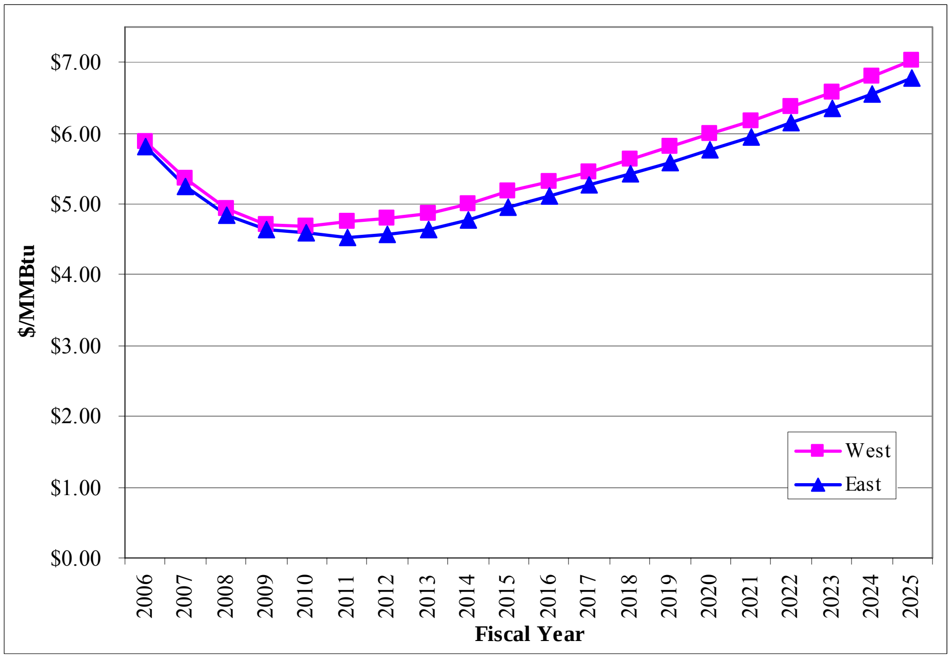
Gas prices on the west side are an average of the Sumas, Stanfield and Opal market hub prices with a \$0.38/MMBtu transportation adder included. Prices on the east side are based upon Opal with a \$0.37/MMBtu transportation adder.

Figure C.1 – Natural Gas and Wholesale Electric Price Curve Components



The blending period is from August 2007 through July 2010. Wholesale Electric prices beginning in August 2010 and through 2023 MIDAS prices are used exclusively. Beyond CY 2023 prices are escalated using the PacifiCorp's inflation rate schedule.

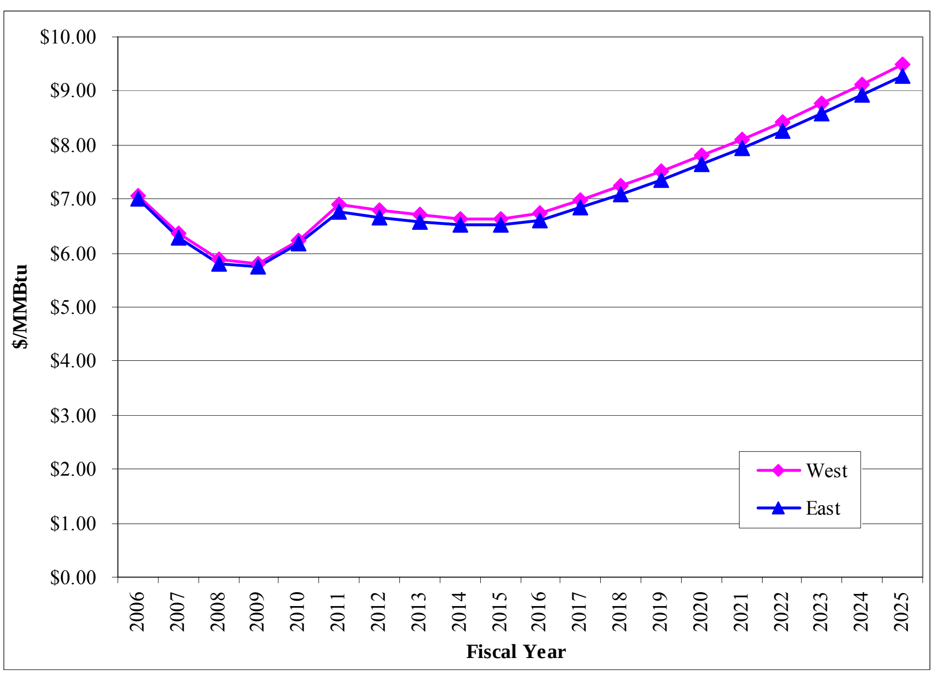
Figure C.2 – PacifiCorp West and East Annual Average Natural Gas Prices



<u>High Gas Price Sensitivity</u>

Figure C.3 summarizes the high gas sensitivity prices used in the scenario analysis (results found in Chapter 8). This curve was developed using the same methodology as in Figure C.1, with the use of recent market information obtained since the June 30, 2004 forecast. Annual Average Natural Gas Prices for West and East are shown.

Figure C.3 – PacifiCorp High Price Gas Curve for Scenario Analysis



Coal Prices

Table C.3 reflects PacifiCorp's estimate of delivered coal costs for Wyoming and Utah. These costs figures are projections and remain sensitive to changes in overall supply and demand as well as changes in transportation costs. The current IRP plan does not contemplate siting of any coal fired plants at other PacifiCorp sites other than Wyoming or Utah. PacifiCorp has not enclosed the costs of its generation fleet. Rather these costs are reflective of PacifiCorp's actual and projected contract costs rather than as a market indicator for future generating potential.

Table C.3 – Annual Average Coal Prices for Resource Additions

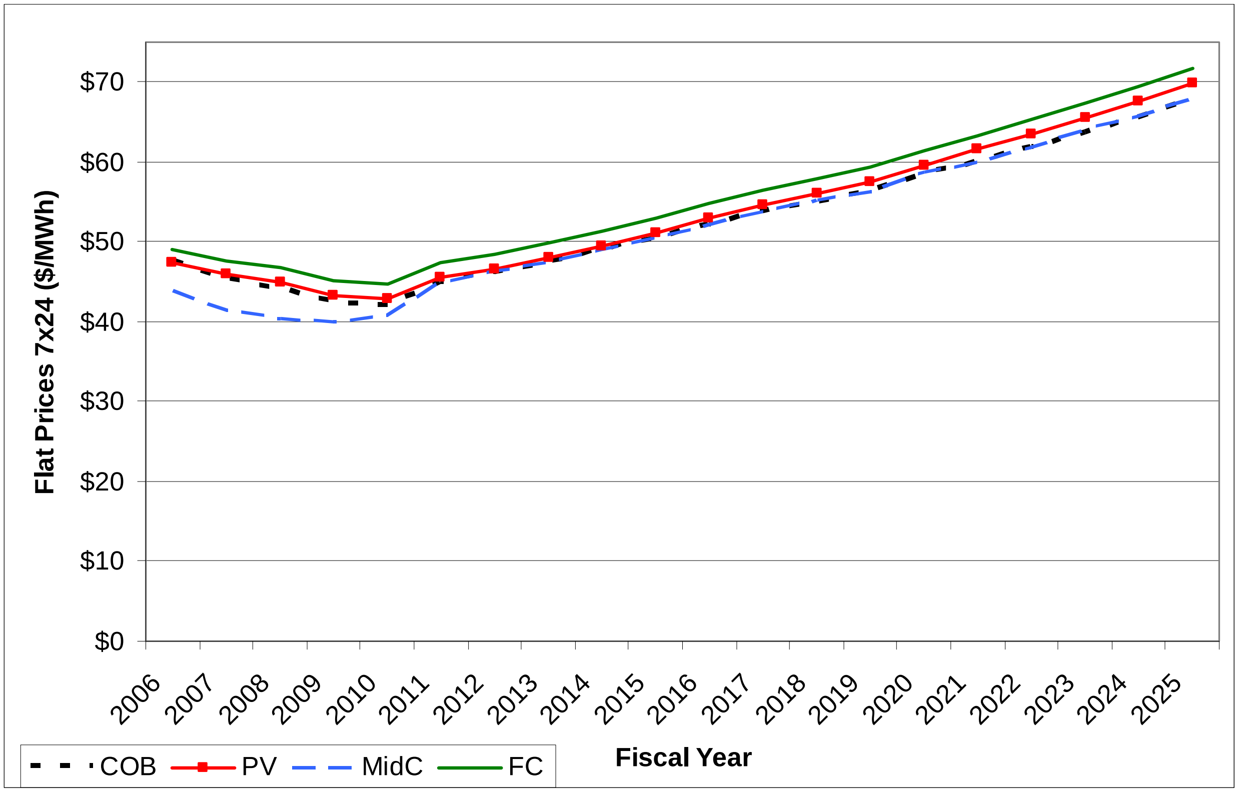
Fiscal Year	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Wyoming	$1.160	$1.190	$1.221	$1.252	$1.285	$1.318	$1.352	$1.388	$1.424	$1.461
Utah	-	-	-	-	-	$1.101	$1.125	$1.150	$1.175	$1.201

Fiscal Year	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Wyoming	$1.499	$1.538	$1.578	$1.620	$1.662	$1.706	$1.750	$1.796	$1.844	$1.892
Utah	$1.228	$1.255	$1.282	$1.310	$1.339	$1.369	$1.399	$1.430	$1.461	$1.493

Wholesale Electricity Prices

Every market valuation of generation resources is significantly influenced by the underlying forecast(s) of wholesale market prices. The commodity nature of the wholesale electric market anticipates that reasonable, well-informed parties will possess different market expectations. The challenge of this IRP process is to find a path that best achieves the identified objectives irrespective of the exact level of market prices in the future. Wholesale electricity prices are modeled through FY 2025 on an hourly basis for Mid-Columbia (MidC), California Oregon Border (COB), Palo Verde (PV) and Four Corners (FC). The electricity price curves represent blended prices from two sources (as of June 30, 2004): near-term forward prices from the market, and long-term fundamental price scenarios simulated in the MIDAS model (See Figure C.1). Figure C.4 shows the flat product ("7 x 24") electricity price curves for each of the four market hubs. Prices are shown in nominal dollars. Reference case market prices for electricity are consistent with PacifiCorp official market price projections, dated June 2004.

Figure C.4 – Wholesale Market Prices



Emission Costs

Sulfur Dioxide (SO_2)

Current vintage allowance prices have been on the rise in 2004, trading at about $215/ton at the beginning of the year and rising to near $500/ton by late summer. Spot SO_2 prices hit an all time high in mid-July 2004, when the market cleared well above $600/ton. The recent rise in SO_2 prices has been sparked by an increasing price spread between low and high sulfur bituminous coals in the east. As the price premium for low sulfur bituminous coal has grown, generators have been acting on the coal price incentive to switch to higher sulfur coals and to use more credits. At the same time, market players with a long position in the SO_2 market have been reluctant to sell given an uncertain regulatory future. This behavior has reduced market liquidity and has added to SO_2 price volatility.

Long-term SO_2 prices are expected to continue their upward climb as tighter emissions limits become more likely. The Clear Skies Act, EPA's proposed Clean Air Interstate Rule (CAIR), and several proposals in Congress all call for further limits on national SO_2 emissions. Any regulatory future that lowers emissions limits will reduce the available supply of SO_2 credits and exert upward pressure on allowance prices. Table C.4 lists the spot SO_2 emission costs used in the IRP. The prices are derived from PIRA projections that assume that tighter SO_2 limits will be fully implemented by 2010.

Table C.4 – SO_2 Spot Price Forecast

Calendar Year	SO_2 ($/Ton)
2005	395
2006	481
2007	559
2008	648
2009	753
2010	877
2011	899
2012	921
2013	944
2014	967
2015	997
2016	1,028
2017	1,061
2018	1,096
2019	1,133
2020	1,172
2021	1,212
2022	1,254
2023	1,298
2024	1,343
2025	1,391

Nitrogen Oxides (NO_X)

The U.S. Environmental Protection Agency's NO_X State Implementation Plan (SIP) Call trading program was initiated for the eastern U.S. in 2004 under a shortened summer ozone trading season, with prices clearing around $2,000/ton. (See Appendix A for background on emission allowance trading programs.) An expanded SIP Call trading program will begin in 2005, when a full 5-month summer trading season is anticipated to push prices higher relative to 2004. In fact, SIP Call 2005 vintage allowances have been trading above $3,000/ton. The SIP Call cap-and-trade program only affects units in the east; therefore, it has no bearing on PacifiCorp. Nonetheless, SIP Call market activity and allowance prices can serve as a guidepost for potential future NO_X policies transitioning into a national, annual trading program.

Table C.5 shows the NO_X prices used in the IRP, which reflect a regulatory future that will impose annual emissions limits on western generators beginning in 2010. The NO_X forecast is derived from PIRA forecasts, which reflect the marginal cost of selective catalytic reduction (SCR) equipment operated over a full year, rather than over a 5-month summer ozone season.

Table C.5 – NO_X Price Forecast

Calendar Year	NO_X ($/Ton)
2010	2,105
2011	2,158
2012	2,210
2013	2,265
2014	2,321
2015	2,393
2016	2,468
2017	2,547
2018	2,631
2019	2,720
2020	2,813
2021	2,908
2022	3,010
2023	3,115
2024	3,224
2025	3,337

Mercury (Hg)

Mercury was addressed under section 112 of the Clean Air Act (CAA) Amendments of 1990, which covers the regulation of hazardous air pollutants. However, source identification and associated rules are not currently defined or enforced. Enforcement under section 112 prohibits the use of a cap-and-trade program to reduce Hg emissions. As a result, EPA has continued down the path of creating best achievable control technology (BACT) standards that would be imposed upon the electric generating sector.

At the same time, EPA has pursued Hg limits under section 111 of the 1990 CAA Amendments with their proposed Clean Air Mercury Rule (CAMR) via a cap-and-trade mechanism. Similarly, several Congressional proposals and the Administration's Clear Skies Act call for Hg limits imposed under a cap-and-trade structure. Mercury prices used in the IRP, shown in Table C.6, are based upon PIRA's forecast for a cap-and-trade policy beginning in CY 2010 with a "backstop" price of $35,000/lb, adjusted for inflation. The notion of a "backstop" price is included as part of the Clear Skies Act and serves as a safety valve should markets soar and reflects the considerable amount of uncertainty that persists regarding the cost to control mercury emissions.

Table C.6 – Mercury Price Forecast

Calendar Year	Mercury Hg ($/lb)
2010	40,934
2011	41,958
2012	42,965
2013	44,039
2014	45,140
2015	46,539

Calendar Year	Mercury Hg ($/lb)
2016	47,982
2017	49,517
2018	51,151
2019	52,890
2020	54,689
2021	56,548
2022	58,527
2023	60,576
2024	62,696
2025	64,890

Carbon Dioxide (CO_2)

There are currently no national regulated standards for CO_2 emissions, although voluntary emission reduction programs and trading markets exist. Several legislative proposals incorporate mandatory CO_2 emission reductions and the establishment of a related trading market, but it remains a significantly contentious issue. In addition, the Kyoto Protocol, while not applying directly in the U.S., may still play an indirect role in terms of placing pressure on U.S. corporations to voluntarily reduce greenhouse gas (GHG) reductions. Other factors include existing and potential state-level regulations as state officials react to public concern.

The IRP imposes CO_2 credit 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 from thereafter. Table C.7 lists the CO_2 prices used in the IRP.

Table C.7 – CO_2 Price Forecast

Calendar Year	CO_2 ($/Ton)
2010	4.19
2011	6.45
2012	8.80
2013	9.02
2014	9.25
2015	9.54
2016	9.83
2017	10.15
2018	10.48
2019	10.84
2020	11.21
2021	11.59
2022	11.99
2023	12.41
2024	12.85

Calendar Year	CO_2 ($/Ton)
2025	13.30

RENEWABLES ASSUMPTIONS

Production Tax Credit

The Production Tax Credit (PTC) incentive applies to new wind and geothermal plants with the intent of bringing their costs in line with traditional thermal resources. In the 2004 IRP, the tax credit applies to wind projects and "closed-loop" biomass projects (e.g., tree plantations devoted to supplying power plants) for the first 10 years of operation at $18/MWh. The credit would also apply to new geothermal and solar plants but only for the first 5 years of operation. "Open-loop" biomass (e.g., urban wood waste, agricultural pruning, etc.), landfill gas, and hydro sited on irrigation networks can earn $9/MWh for five years. Annual net operating expenses are directly credited at $18/MWh for each MWh produced by wind and geothermal plants for each year the incentive applies. This is an effective simplification for applying the cost. In reality, the benefits of the tax credit do not apply to the bottom line in such a straightforward manner. The PTC was recently extended by Congress for facilities entering service by December 2005. Based on historical experience, PacifiCorp expects continued renewal of the PTC past CY 2005 for long term planning purposes.

Green Tags

Green tags are certificates that represent the environmental attributes of renewable energy generation not present in fossil fuel fired generation such as coal or natural gas. Such attributes can be traded between parties and therefore have a dollar value. New wind and geothermal plants are assumed to have a green tag value of $5/MWh for the first five years of production. This rate does not change through time, effectively reducing their value by inflation each year.

Base Case Renewables Assumption

Within the base case assumptions for the 2004 IRP, PacifiCorp retains the 2003 IRP conclusion that 1,400 MW of renewables, modeled as wind resources, will continue to be cost effective and help lower overall system costs by reducing emissions and fuel costs. PacifiCorp concludes that it is valid to use this assumption based on the review of RFP 2003-B responses, and analysis using Henwood's Capacity Expansion Model (CEM), which is described in more detail in Appendix J. Table C.8 illustrates the size and timing of the new renewable resources present in every portfolio of this IRP.

Table C.8 – Base Renewable Resource Additions in Megawatts

Location	FY 06	FY 07	FY 08	FY 09	FY 10	FY 11	FY 12	FY 13	FY 14	FY 15
EAST	0	200	0	200	0	200	100	100	0	0
WEST	100	0	200	0	200	0	100	0	0	0
TOTAL	**100**	**200**	**200**	**200**	**200**	**200**	**200**	**100**	**0**	**0**

Wind Capacity Planning Contribution

For the 2004 IRP, PacifiCorp used a 20% capacity contribution for planning purposes when considering new wind resources. Therefore, the 1,400 MW of wind modeled in the base level of resources for all portfolios, contributes 280 MW towards the planning margin requirement. Please refer to Appendix J for an in-depth review of renewable resource assumptions for the 2004 IRP.

EXISTING RESOURCES AND PLANNED RESOURCES

Contracts

A number of contracts were modeled in the IRP analysis. Table C.9 shows the basic information for each contract by classification of exchange, purchase, or sale. Values shown are maximum annual values. The table includes purchase and sale categories for forward/cash transactions.

Table C.9 – Contracts - Annual MW per contract / per year

Exchange

	Counterparty	Description	End Date	FY2006	FY2007	FY2008	FY2009	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2020	FY2025
1	Arizona Public Service Company	Long-Term Power Transactions	2/2021	480	480	480	480	480	480	480	480	480	480	480	-
2	Arizona Public Service Company	Long-Term Power Transactions	2/2031	95	95	95	95	95	95	95	95	95	95	95	95
3	Arizona Public Service Company	Long-Term Power Transactions	9/2020	-	-	-	-	-	-	-	-	-	-	-	-
4	Arizona Public Service Company	Long-Term Power Transactions	9/2020	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	-
5	Bonneville Power Administration	South Idaho Exchange	GTC	204	204	204	204	204	204	204	204	204	204	204	188
6	Bonneville Power Administration	South Idaho Exchange	GTC	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
7	Bonneville Power Administration	Spring Energy Delivery	6/2014	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	-	-
8	Bonneville Power Administration	Summer Storage Return	6/2014	(93)	(93)	(93)	(93)	(93)	(93)	(93)	(93)	(93)	139	-	-
9	Bonneville Power Administration	South Idaho Exchange	GTC	195	198	213	213	213	213	213	241	241	241	258	234
10	Bonneville Power Administration	Foote Creek II Wind Exchange	6/2014	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	-	-
11	Bonneville Power Administration	Foote Creek II Wind Exchange	6/2014	1	1	1	1	1	1	1	1	1	1	-	-
12	City of Redding	Exchange Agreement	12/2015	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	-	-
13	City of Redding	Exchange Agreement	12/2015	21	21	21	21	21	21	21	21	21	21	-	-
14	Seattle City Light	Wind Exchange	2/2012	(55)	(55)	(55)	(55)	(55)	(55)	(55)	-	-	-	-	-
15	Seattle City Light	Wind Exchange	2/2012	58	58	58	58	58	58	58	-	-	-	-	-
16	Public Service Co of Colorado	Transmission Service Agreement	4/2007	40	40	40	-	-	-	-	-	-	-	-	-
17	Public Service Co of Colorado	Transmission Service Agreement	4/2007	(40)	(40)	(40)	-	-	-	-	-	-	-	-	-
18	Public Service Co of Colorado	Foote Creek III Generation Control/Storage/Delivery	9/2014	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	-	-
19	Public Service Co of Colorado	Foote Creek III Generation Control/Storage/Delivery	9/2014	15	15	15	15	15	15	15	15	15	15	-	-
20	Sacramento Municipal Utility Dist	Exchange Agreement Additional Energy	1/2015	100	100	100	100	100	100	100	100	100	100	-	-
21	Sacramento Municipal Utility Dist	Exchange Agreement Power Sale	1/2015	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	-	-

Purchase

	Counterparty	Description	End Date	FY2006	FY2007	FY2008	FY2009	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2020	FY2025
22	Arizona Public Service Company	Supplemental Energy Purchase Optn	10/2020	250	250	250	250	250	250	250	250	250	250	250	-
23	Arizona Public Service Company	Power Purchase	4/2008	50	50	50	-	-	-	-	-	-	-	-	-
24	Arizona Public Service Company	Power Purchase	9/2007	25	25	25	-	-	-	-	-	-	-	-	-
25	AVISTA / Colstrip Owners	Service Agreement	10/2008	1	1	1	1	-	-	-	-	-	-	-	-
26	Clark County PUD No.1	Base Capacity	12/2007	661	661	661	-	-	-	-	-	-	-	-	-
27	Clark County PUD No.1	Load Servicing/Exchange Agreement	12/2007	(220)	(228)	(228)	-	-	-	-	-	-	-	-	-
28	Clark County PUD No.1	Forced Outage Reserve	12/2007	10	10	10	-	-	-	-	-	-	-	-	-
29	Combine Hills	Purchase of Wind	12/2023	41	41	41	41	41	41	41	41	41	41	41	-
30	Constellation Power Source	Power Purchase Agreement	9/2005	150	-	-	-	-	-	-	-	-	-	-	-
31	Deseret	Power Purchase	9/2024	100	100	100	100	100	100	100	100	100	100	100	100
32	Douglas County PUD No.1	Energy Purchase Agreement	9/2018	15	15	15	15	15	15	15	15	15	15	-	-
33	Duke Energy Trading	Power Purchase	12/2006	50	50	-	-	-	-	-	-	-	-	-	-
34	J. Aron & Company	Power Purchase	8/2005	25	-	-	-	-	-	-	-	-	-	-	-
35	Morgan Stanley	Power Purchase Agreement	8/2006	50	50	-	-	-	-	-	-	-	-	-	-
36	Morgan Stanley	Power Purchase Agreement	12/2010	-	50	50	50	50	50	-	-	-	-	-	-
37	Pinnacle West Capital Corporation	Power Purchase Agreement	9/2005	50	-	-	-	-	-	-	-	-	-	-	-
38	Portland General Electric	Cove Replacement Power	GTC	1	1	1	1	1	1	1	1	1	1	1	1
39	PowerEx	Power Purchase	9/2005	92	-	-	-	-	-	-	-	-	-	-	-
40	Public Service Co of New Mexico	Power Purchase Agreement	9/2005	100	-	-	-	-	-	-	-	-	-	-	-
41	Public Service Co of New Mexico	Power Purchase Agreement	8/2005	50	-	-	-	-	-	-	-	-	-	-	-
42	River Road CCCT	Load Servicing/Exchange Agreement	12/2007	240	240	-	-	-	-	-	-	-	-	-	-
43	Rock River I	Power Purchase Agreement	12/2022	22	22	22	22	22	22	22	22	22	22	22	-
44	Southern California Edison	Power Sales Agreement	9/2006	150	150	-	-	-	-	-	-	-	-	-	-
45	TransAlta Energy Marketing	Power Purchase Agreement	7/2007	400	400	400	-	-	-	-	-	-	-	-	-
46	Various short term firm purchases*	Forward Price - Aggregate Summary	2006, 2007	150	75	-	-	-	-	-	-	-	-	-	-

Table C.9 – Contracts - Annual MW per contract / per year (Continued)

Sale

	Counterparty	Description	End Date	FY2006	FY2007	FY2008	FY2009	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2020	FY2025
45	Black Hills Corporation	Power Sales Agreement	12/2023	(100)	(100)	(100)	(89)	(89)	(100)	(100)	(100)	(100)	(89)	(100)	-
46	Bonneville Power Administration	Foote Creek I Wind Exchange	4/2024	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(7)
47	Bonneville Power Administration Flathead	Power Sales Agreement	10/2006	(70)	(70)	-	-	-	-	-	-	-	-	-	-
48	Bonneville Power Administration EWEB-Foote Creek I	Generation Control, Storage and Power Supply Agreement	4/2024	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(3)
49	Grant County PUD No. 2	CEAEA	9/2024	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
50	Public Service Co of Colorado	Power Sales Agreement	11/2011	(176)	(176)	(141)	(107)	(71)	(36)	(36)	-	-	-	-	-
51	RTSA	RTSA losses-ID Power Co.	GTC	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
52	Sierra Pacific Power Company	Power Sales Agreement	3/2009	(75)	(75)	(75)	(75)	-	-	-	-	-	-	-	-
53	Utah Municipal Power Agency	Electric Supply Agreement	7/2005	(8)	-	-	-	-	-	-	-	-	-	-	-
54	Utah Municipal Power Agency	Power Sales Agreement	7/2017	(88)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	-	-
55	Various short term firm sales*	Forward Price - Aggregate Summary	2006, 2007	(1,200)	(300)	-	-	-	-	-	-	-	-	-	-

Interruptible

	Counterparty	Description	End Date	FY2006	FY2007	FY2008	FY2009	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2020	FY2025
56	Monsanto	Full Requirements Retail Load	12/2006	67	67	-	-	-	-	-	-	-	-	-	-
57	Nucor	Electric Supply (and Interruption) agreement	12/2006	60	60	60	60	60	60	60	60	60	60	60	-

Lease

	Counterparty	Description	End Date	FY2006	FY2007	FY2008	FY2009	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2020	FY2025
58	LEASECO, a wholly owned subsidiary of PPM	Lease of Generators at West Valley Utah	12/2017	200	200	200	200	200	200	200	200	200	200	-	-

Hydro

	Counterparty	Description	End Date	FY2006	FY2007	FY2008	FY2009	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2020	FY2025
59	Bonneville Power Administration	BPA Return portion of exchange	8/2011	(575)	(575)	(575)	(575)	(575)	(575)	(575)	-	-	-	-	-
60	Bonneville Power Administration	BPA Take portion of exchange	8/2011	575	575	575	575	575	575	575	-	-	-	-	-
61	Gem State (Idaho Falls)	Power Purchase Agreement	8/2023	22	22	22	22	22	22	22	22	22	22	22	22
62	Grant County PUD No. 2	Power Purchase Agreement	GTC	14	14	14	14	14	14	14	14	14	14	14	14
63	Tri-State Generation and Transmission	Power Sales Agreement	12/2020	40	35	30	25	25	25	25	25	25	25	25	
64	*Mid-Columbia Hydro:* Chelan County PUD No.1	Power Purchase Agreement	12/2011	-	-	-	-	-	-	-	-	-	-	-	-
65	*Mid-Columbia Hydro:* Douglas County PUD No.1	Settlement Agreement, Power Purchase Agreement	8/2018	-	-	-	-	-	-	-	-	-	-	-	-
66	*Mid-Columbia Hydro:* Grant County PUD No.2	Power Purchase Agreement, Surplus, Displacement Energy, Priest Rapids, Sales	2005, 2011, 2029, 2058	-	-	-	-	-	-	-	-	-	-	-	-
67	**TOTAL *Mid-Columbia Hydro:* (See above)**	**Mid-Columbia Hydro**		**406**	**306**	**306**	**306**	**301**	**189**	**188**	**126**	**126**	**126**	**74**	**74**

Notes

* Due to the sizable number of these transactions the MW value reported is an aggregate annual total (37 for sales and 15 for purchases).

GTC: Good Till Cancelled

Demand Side Management

This section provides tabular statistics for PacifiCorp's Class 1 and 2 DSM programs. For more information on DSM programs, see the following:

- Chapter 2 describes each of the DSM program classes.
- Chapter 5 summarizes how Class 1 and Class 2 DSM were incorporated in the portfolio simulation and analysis process. (Note that Class 3 and 4 DSM are not modeled given that they are not considered as long-term, reliable IRP resources.)

Class 1 DSM

Table C.10 details the base case Class 1 DSM Programs. Peak load reductions for the FY 2005-2014 period are shown by program within each State.

Table C.10 – Class 1 DSM Programs

DSM Program Name	Description	Program Contribution (MW)	Availability
Irrigation Load Control	Incentive program for Idaho irrigation customers to participate in pumping load control program during the irrigation season.	35 MW in FY 2005 continuing for 10 years.	ID
Residential and Small Commercial A/C Load Control Program –"Cool Keeper"	Turn-key load control network financed, built, operated and owned by a third party vendor through a pay-for-performance contract.	60 MW by FY 2006 growing to 90 MW by FY 2007. Continues through FY 2014.	UT
Commercial and Industrial Lighting Load Control	Incentives for commercial and industrial customers to participate in lighting control.	Program to start in FY 2006, growing to 27 MW by FY 2008.	UT

Class 2 DSM

Table C.11 defines the Class 2 programs. Tables C.12 through C.22 detail the base case Class 2 DSM programs. Annual average load reductions for the FY 2005-2014 period are shown by program within each State. These programs are included as reductions to the 2004 IRP base case load forecast.

Table C.11 – Class 2 DSM Programs

DSM Program Name	Description
Energy FinAnswer (incentive program)	Engineering & incentive package for improved energy efficiency in new construction and comprehensive retrofit projects in commercial, industrial and irrigation sectors. Incentives are based on $/kWh and $/kW reductions.
Energy FinAnswer (loan program)	Engineering & financing package for improved energy efficiency in new construction and retrofit projects. Commercial, industrial and irrigation.

DSM Program Name	Description
Energy FinAnswer Express	Incentives for single measure new construction and retrofit energy-efficient projects in commercial, industrial and irrigation sectors. Incentives are based on a prescriptive (pre-determined) amount dependent on measures installed.
Commercial and Industrial Retro Commissioning	Building tune-up services designed to provide customers with low to no cost actions they can take to improve the efficiency of their existing equipment or facilities.
Self-Direction Credit Projects	Provides large business customers the opportunity to receive credits to offset the Customer Efficiency Services charge for qualified "self-investments" in efficiency and related demand side management projects.
Irrigation Efficiency	Three part program. Nozzle exchange, pump check and water management consultation, and pump testing that includes a system audit function. Major changes such as system re-design and replacements are referred to the FinAnswer Programs.
C&I Lighting Load Control 3%	Energy savings component of Class 1 C&I Lighting Load Control Program. Participating customers load control equipment is pre-set to deliver steady 3% energy savings as their incentive to participation.
Efficient Air Conditioning Program – "Cool Cash"	Provide customer incentives for improving the efficiency of air conditioning equipment and/or maintaining or converting air conditioning equipment to evaporative cooling technologies.
Residential New Construction – "Energy Star Homes"	Third party delivered program providing incentives for home builders to construct single and multi-family homes that exceed energy code requirements. Homes will be required to have more efficient cooling equipment and a mix of improved shell measures (windows and insulation) to be eligible for incentives. Additional incentives will be available for improved lighting, and evaporative cooling.
Appliance Recycling Program	An incentive program designed to remove inefficient refrigerators from the market.
Low-Income Weatherization Program	The Company partners with community action agencies to provide no cost residential weatherization services to income qualifying households.
Washwise	Limited time rebate program to encourage the market penetration of horizontal axis washing machines. Run in conjunction with NEEA's April-May regional advertising campaign.
Energy Education	Program provides 6th graders with energy efficiency curriculum and home energy audit kits that include instant savings measures i.e. CFLs, showerheads, temp check cards, etc.
Do-It-Yourself Energy Audit (Paper or Web based)	Residential and small commercial web or paper based energy audit. Fill in the audit information and program provides an energy analysis of your home or business. Customers who complete the audit receive instant saving measures mailed to their home (CFL, Low Flow Showerhead, etc.).
Northwest Energy Efficiency Alliance (NEEA)	A series of conservation programs sponsored by utilities in the region and delivered through NEEA designed to support market transformation of energy efficient products and services in OR, WA, ID and MT. Programs include manufacturer rebates on compact fluorescent bulbs to building operator certification courses.
Energy Trust of Oregon (ETO)	Energy education and conservation measures implemented by the Energy Trust of Oregon with funding from the three- percent public purpose charge for Oregon customers.

Table C.12 – Class 2 DSM Service Area Totals

Class 2 Service Area Total (All Energy and Demand Figures are at the load)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	22.58	197,786	$ 19,306,733	22.58	197,786
2006	27.17	238,581	$ 24,916,122	49.75	436,367
2007	28.88	252,957	$ 27,805,000	78.63	689,324
2008	28.64	250,955	$ 28,031,000	107.27	940,279
2009	25.68	224,933	$ 23,061,000	132.94	1,165,212
2010	24.61	215,586	$ 21,211,000	157.55	1,380,798
2011	24.07	210,812	$ 18,666,000	181.62	1,591,609
2012	24.20	211,951	$ 18,491,000	205.81	1,803,560
2013	15.10	132,235	$ 18,491,000	220.91	1,935,795
2014	13.40	117,343	$ 18,491,000	233.40	2,045,253

PacifiCorp Program Totals

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	12.98	113,690	$ 19,306,733	12.98	113,690
2006	15.67	137,841	$ 24,916,122	28.65	251,531
2007	17.88	156,597	$ 27,805,000	46.53	408,128
2008	18.54	162,479	$ 28,031,000	65.07	570,607
2009	15.48	135,581	$ 23,061,000	80.54	706,188
2010	14.11	123,606	$ 21,211,000	94.65	829,794
2011	13.47	117,956	$ 18,666,000	108.12	947,749
2012	13.40	117,343	$ 18,491,000	121.51	1,065,092
2013	13.40	117,343	$ 18,491,000	134.91	1,182,435
2014	13.40	117,343	$ 18,491,000	147.40	1,291,893

Energy Trust of Oregon Total

Calendar Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	9.60	84,096	$ -	9.60	84,096
2006	11.50	100,740	$ -	21.10	184,836
2007	11.00	96,360	$ -	32.10	281,196
2008	10.10	88,476	$ -	42.20	369,672
2009	10.20	89,352	$ -	52.40	459,024
2010	10.50	91,980	$ -	62.90	551,004
2011	10.60	92,856	$ -	73.50	643,860
2012	10.80	94,608	$ -	84.30	738,468
2013	1.70	14,892	$ -	86.00	753,360
2014	-	-	$ -	86.00	753,360

Peak Hour DSM Savings (MW)

Fiscal Year	CA	WY	ID	OR	UT	WA	Total
2006	0	0	3	13	34	8	58
2007	1	1	5	28	51	13	99
2008	1	2	7	43	68	17	138
2009	1	5	9	56	84	21	176
2010	2	7	11	70	97	23	210
2011	2	9	12	84	107	26	240
2012	2	11	13	98	118	27	269
2013	2	13	14	112	130	29	300
2014	3	15	15	115	143	31	322
2015	3	15	15	116	143	31	323

Class 2 DSM – Program Totals
Table C.13 – Class 2 DSM Program Totals, Commercial and Industrial Programs

Energy FinAnswer (Sched. 125)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	5.28	46,253	$ 7,750,000	5.28	46,253
2006	6.53	57,203	$ 9,790,000	11.81	103,456
2007	7.75	67,890	$ 11,615,000	19.56	171,346
2008	8.41	73,672	$ 12,615,000	27.97	245,017
2009	8.41	73,672	$ 12,615,000	36.38	318,689
2010	8.34	73,058	$ 12,505,000	44.72	391,747
2011	8.29	72,620	$ 12,430,000	53.01	464,368
2012	8.24	72,182	$ 12,355,000	61.25	536,550
2013	8.24	72,182	$ 12,355,000	69.49	608,732
2014	8.24	72,182	$ 12,355,000	77.73	680,915

Retro Commissioning

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulativ e	MWh Cumulative
2005	-	-	$ -	-	-
2006	0.16	1,402	$ 400,000	0.16	1,402
2007	0.22	1,927	$ 550,000	0.38	3,329
2008	0.24	2,102	$ 600,000	0.62	5,431
2009	0.28	2,453	$ 700,000	0.90	7,884
2010	-	-	$ -	0.90	7,884
2011	-	-	$ -	0.90	7,884
2012	-	-	$ -	0.90	7,884
2013	-	-	$ -	0.90	7,884
2014	-	-	$ -	-	-

FasTrack (formerly Retrofit Incentive, Sched. 115, 116)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	2.00	17,520	$ 2,900,000	2.00	17,520
2006	2.18	19,123	$ 3,058,122	4.18	36,643
2007	2.39	20,901	$ 3,350,000	6.57	57,544
2008	2.44	21,374	$ 3,425,000	9.01	78,919
2009	2.44	21,374	$ 3,290,000	11.45	100,293
2010	2.44	21,374	$ 3,290,000	13.89	121,668
2011	2.44	21,374	$ 3,290,000	16.33	143,042
2012	2.44	21,374	$ 3,290,000	18.77	164,416
2013	2.44	21,374	$ 3,290,000	21.21	185,791
2014	2.44	21,374	$ 3,290,000	23.65	207,165

Self-Direction Credit projects (Sched. 192)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulativ e	MWh Cumulative
2005	0.90	7,884	$ 300,000	0.90	7,884
2006	0.80	7,008	$ 325,000	1.70	14,892
2007	0.90	7,884	$ 360,000	2.60	22,776
2008	0.90	7,884	$ 360,000	3.50	30,660
2009	0.90	7,884	$ 360,000	4.40	38,544
2010	0.90	7,884	$ 360,000	5.30	46,428
2011	0.90	7,884	$ 360,000	6.20	54,312
2012	0.90	7,884	$ 360,000	7.10	62,196
2013	0.90	7,884	$ 360,000	8.00	70,080
2014	0.90	7,884	$ 360,000	8.90	77,964

Irrigation Efficiency

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	-	-	$ -	-	-
2006	0.24	2,124	$ 416,000	0.24	2,124
2007	0.24	2,124	$ 470,000	0.49	4,249
2008	0.24	2,124	$ 470,000	0.73	6,373
2009	-	-	$ -	0.73	6,373
2010	-	-	$ -	0.73	6,373
2011	-	-	$ -	0.73	6,373
2012	-	-	$ -	0.73	6,373
2013	-	-	$ -	0.73	6,373
2014	-	-	$ -	0.73	6,373

C&I Lighting Load Control 3%

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulativ e	MWh Cumulative
2005	-	-	$ -	-	-
2006	0.40	3,504	$ -	0.40	3,504
2007	0.90	7,884	$ -	1.30	11,388
2008	1.45	12,702	$ -	2.75	24,090
2009	1.45	12,702	$ -	4.20	36,792
2010	1.45	12,702	$ -	5.65	49,494
2011	1.45	12,702	$ -	7.10	62,196
2012	1.45	12,702	$ -	8.55	74,898
2013	1.45	12,702	$ -	10.00	87,600
2014	1.45	12,702	$ -	11.45	100,302

Table C.14 – Class 2 DSM Program Totals, Residential Programs

Efficient Cooling, "Cool Cash and Coupons"

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.40	3,504	$ 2,900,000	0.40	3,504
2006	0.36	3,154	$ 2,515,000	0.76	6,658
2007	0.41	3,548	$ 2,595,000	1.17	10,205
2008	0.40	3,460	$ 2,575,000	1.56	13,666
2009	0.15	1,270	$ 825,000	1.71	14,936
2010	0.15	1,270	$ 820,000	1.85	16,206
2011	0.11	964	$ 750,000	1.96	17,170
2012	0.11	964	$ 750,000	2.07	18,133
2013	0.11	964	$ 750,000	2.18	19,097
2014	0.11	964	$ 750,000	2.29	20,060

Low Income Weatherization

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.13	1,141	$1,356,733	0.13	1,141
2006	0.26	2,236	$1,736,000	0.39	3,377
2007	0.26	2,236	$1,736,000	0.64	5,614
2008	0.26	2,236	$1,736,000	0.90	7,850
2009	0.26	2,236	$1,736,000	1.15	10,086
2010	0.26	2,236	$1,736,000	1.41	12,322
2011	0.26	2,236	$1,736,000	1.66	14,558
2012	0.26	2,236	$1,736,000	1.92	16,795
2013	0.26	2,236	$1,736,000	2.17	19,031
2014	0.26	2,236	$1,736,000	2.43	21,267

Appliance Recycling, "See 'ya later refrigerator"

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	3.17	27,769	$ 2,700,000	3.17	27,769
2006	3.20	28,568	$ 3,260,000	6.37	56,337
2007	3.07	26,903	$ 3,080,000	9.44	83,240
2008	2.59	22,774	$ 2,600,000	12.03	106,014
2009	-	-	$ -	12.03	106,014
2010	-	-	$ -	12.03	106,014
2011	-	-	$ -	12.03	106,014
2012	-	-	$ -	12.03	106,014
2013	-	-	$ -	12.03	106,014
2014	-	-	$ -	12.03	106,014

New Construction

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	-	-	$ -	-	-
2006	0.40	3,504	$1,855,000	0.40	3,504
2007	0.57	5,028	$2,450,000	0.97	8,532
2008	0.59	5,168	$2,535,000	1.56	13,701
2009	0.59	5,168	$2,535,000	2.15	18,869
2010	0.58	5,081	$2,500,000	2.73	23,950
2011	0.02	175	$ 100,000	2.75	24,125
2012	-	-	$ -	2.75	24,125
2013	-	-	$ -	2.75	24,125
2014	-	-	$ -	2.75	24,125

Do-it-Yourself Energy Audit (Paper or Web based)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.01	70	$ 300,000	0.01	70
2006	0.01	70	$ 300,000	0.02	140
2007	0.01	61	$ 250,000	0.02	201
2008	0.01	61	$ 250,000	0.03	263
2009	0.01	61	$ 200,000	0.04	324
2010	-	-	$ -	0.04	324
2011	-	-	$ -	0.04	324
2012	-	-	$ -	0.04	324
2013	-	-	$ -	0.04	324
2014	-	-	$ -	0.04	324

Energy Education

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.09	788	$ 300,000	0.09	788
2006	0.10	876	$ 335,000	0.19	1,664
2007	0.11	964	$ 352,000	0.30	2,628
2008	-	-	$ -	0.30	2,628
2009	-	-	$ -	0.30	2,628
2010	-	-	$ -	0.30	2,628
2011	-	-	$ -	0.30	2,628
2012	-	-	$ -	0.30	2,628
2013	-	-	$ -	0.30	2,628
2014	-	-	$ -	0.30	2,628

Washwise

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	-	-	$ -	-	-
2006	0.04	310	$ 126,000	0.04	310
2007	0.06	485	$ 197,000	0.09	795
2008	0.02	160	$ 65,000	0.11	956
2009	-	-	$ -	0.11	956
2010	-	-	$ -	0.11	956
2011	-	-	$ -	0.11	956
2012	-	-	$ -	0.11	956
2013	-	-	$ -	0.11	956
2014	-	-	$ -	0.11	956

Table C.15 – Class 2 DSM Program Totals, Summary Totals

Northwest Energy Efficiency Alliance

All Programs

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	1.00	8,760	$ 800,000	1.00	8,760
2006	1.00	8,760	$ 800,000	2.00	17,520
2007	1.00	8,760	$ 800,000	3.00	26,280
2008	1.00	8,760	$ 800,000	4.00	35,040
2009	1.00	8,760	$ 800,000	5.00	43,800
2010	-	-	$ -	5.00	43,800
2011	-	-	$ -	5.00	43,800
2012	-	-	$ -	5.00	43,800
2013	-	-	$ -	5.00	43,800
2014	-	-	$ -	5.00	43,800

Energy Trust of Oregon

All Programs

Calendar Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	9.60	84,096	$ -	9.60	84,096
2006	11.50	100,740	$ -	21.10	184,836
2007	11.00	96,360	$ -	32.10	281,196
2008	10.10	88,476	$ -	42.20	369,672
2009	10.20	89,352	$ -	52.40	459,024
2010	10.50	91,980	$ -	62.90	551,004
2011	10.60	92,856	$ -	73.50	643,860
2012	10.80	94,608	$ -	84.30	738,468
2013	1.70	14,892	$ -	86.00	753,360
2014	-	-	$ -	86.00	753,360

Class 2 DSM – Totals by State

Table C.16 – Class 2 DSM – Totals by State

California State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.01	90	150,000	0.01	90
2006	0.26	2,249	553,000	0.27	2,339
2007	0.50	4,369	920,000	0.77	6,709
2008	0.51	4,492	945,000	1.28	11,201
2009	0.44	3,857	800,000	1.72	15,057
2010	0.37	3,244	690,000	2.09	18,301
2011	0.32	2,806	615,000	2.41	21,107
2012	0.27	2,368	540,000	2.68	23,474
2013	0.27	2,368	540,000	2.95	25,842
2014	0.27	2,368	540,000	3.22	28,209

Utah State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	9.66	84,622	13,600,000	9.66	84,622
2006	10.12	88,651	15,640,000	19.78	173,273
2007	11.54	101,090	17,265,000	31.32	274,363
2008	12.47	109,237	18,015,000	43.79	383,600
2009	10.26	89,878	14,365,000	54.05	473,478
2010	9.98	87,425	13,665,000	64.03	560,903
2011	9.48	83,045	11,565,000	73.51	643,948
2012	9.48	83,045	11,565,000	82.99	726,992
2013	9.48	83,045	11,565,000	92.47	810,037
2014	9.48	83,045	11,565,000	101.05	885,198

Idaho State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.61	5,344	562,000	0.61	5,344
2006	1.13	10,469	1,393,000	1.74	15,813
2007	1.94	17,039	2,708,000	3.69	32,852
2008	1.93	17,021	2,772,000	5.62	49,874
2009	1.56	13,622	2,182,000	7.18	63,496
2010	1.12	9,767	1,825,000	8.29	73,263
2011	1.10	9,592	1,755,000	9.39	82,855
2012	1.08	9,417	1,655,000	10.46	92,272
2013	1.08	9,417	1,655,000	11.54	101,689
2014	1.08	9,417	1,655,000	12.61	111,106

Washington State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	2.59	22,671	4,839,733	2.59	22,671
2006	4.05	35,508	7,049,122	6.64	58,179
2007	3.78	33,134	6,631,000	10.42	91,312
2008	3.51	30,765	6,018,000	13.94	122,078
2009	3.11	27,261	5,433,000	17.05	149,339
2010	2.54	22,207	4,750,000	19.58	171,545
2011	2.46	21,550	4,450,000	22.04	193,095
2012	2.46	21,550	4,450,000	24.50	214,645
2013	2.46	21,550	4,450,000	26.96	236,194
2014	2.46	21,550	4,450,000	29.42	257,744

Oregon State Total for Energy Trust

Calendar Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	9.60	84,096	0	9.60	84,096
2006	11.50	100,740	0	21.10	184,836
2007	11.00	96,360	0	32.10	281,196
2008	10.10	88,476	0	42.20	369,672
2009	10.20	89,352	0	52.40	459,024
2010	10.50	91,980	0	62.90	551,004
2011	10.60	92,856	0	73.50	643,860
2012	10.80	94,608	0	84.30	738,468
2013	1.70	14,892	0	86.00	753,360
2014	0.00	0	0	86.00	753,360

Wyoming State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.11	964	155,000	0.11	964
2006	0.11	964	281,000	0.22	1,927
2007	0.11	964	281,000	0.33	2,891
2008	0.11	964	281,000	0.44	3,854
2009	0.11	964	281,000	0.55	4,818
2010	0.11	964	281,000	0.66	5,782
2011	0.11	964	281,000	0.77	6,745
2012	0.11	964	281,000	0.88	7,709
2013	0.11	964	281,000	0.99	8,672
2014	0.11	964	281,000	1.10	9,636

California

Table C.17 – Class 2 DSM California

Commercial and Industrial Programs

Energy FinAnswer (Sched. 125)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005				0.00	0
2006	0.15	1,314	225,000	0.15	1,314
2007	0.37	3,241	560,000	0.52	4,555
2008	0.37	3,241	560,000	0.89	7,796
2009	0.37	3,241	560,000	1.26	11,038
2010	0.30	2,628	450,000	1.56	13,666
2011	0.25	2,190	375,000	1.81	15,856
2012	0.20	1,752	300,000	2.01	17,608
2013	0.20	1,752	300,000	2.21	19,360
2014	0.20	1,752	300,000	2.41	21,112

Irrigation Efficiency

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005			0	0.00	0
2006	0.07	635	145,000	0.07	635
2007	0.07	635	145,000	0.15	1,270
2008	0.07	635	145,000	0.22	1,905
2009				0.22	1,905
2010				0.22	1,905
2011				0.22	1,905
2012				0.22	1,905
2013				0.22	1,905
2014				0.22	1,905

FinAnswer Express (formerly Retrofit Incentive, Sched. 115)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005		0		0.00	0
2006	0.02	210	33,000	0.02	210
2007	0.05	403	65,000	0.07	613
2008	0.06	526	90,000	0.13	1,139
2009	0.06	526	90,000	0.19	1,664
2010	0.06	526	90,000	0.25	2,190
2011	0.06	526	90,000	0.31	2,716
2012	0.06	526	90,000	0.37	3,241
2013	0.06	526	90,000	0.43	3,767
2014	0.06	526	90,000	0.49	4,292

Residential Programs

Low Income Weatherization

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.01	90	150,000	0.01	90
2006	0.01	90	150,000	0.02	180
2007	0.01	90	150,000	0.03	270
2008	0.01	90	150,000	0.04	360
2009	0.01	90	150,000	0.05	450
2010	0.01	90	150,000	0.06	540
2011	0.01	90	150,000	0.07	630
2012	0.01	90	150,000	0.08	720
2013	0.01	90	150,000	0.09	810
2014	0.01	90	150,000	0.10	900

California State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.01	90	150,000	0.01	90
2006	0.26	2,249	553,000	0.27	2,339
2007	0.50	4,369	920,000	0.77	6,709
2008	0.51	4,492	945,000	1.28	11,201
2009	0.44	3,857	800,000	1.72	15,057
2010	0.37	3,244	690,000	2.09	18,301
2011	0.32	2,806	615,000	2.41	21,107
2012	0.27	2,368	540,000	2.68	23,474
2013	0.27	2,368	540,000	2.95	25,842
2014	0.27	2,368	540,000	3.22	28,209

Idaho

Table C.18 – Class 2 DSM Idaho

Commercial and Industrial Programs

Energy FinAnswer (Sched. 125)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.16	1,402	175,000	0.16	1,402
2006	0.28	2,453	415,000	0.44	3,854
2007	0.94	8,234	1,405,000	1.38	12,089
2008	0.94	8,234	1,405,000	2.32	20,323
2009	0.94	8,234	1,405,000	3.26	28,558
2010	0.94	8,234	1,405,000	4.20	36,792
2011	0.94	8,234	1,405,000	5.14	45,026
2012	0.94	8,234	1,405,000	6.08	53,261
2013	0.94	8,234	1,405,000	7.02	61,495
2014	0.94	8,234	1,405,000	7.96	69,730

Irrigation Efficiency

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005		0	0	0.00	0
2006	0.17	1,489	271,000	0.17	1,489
2007	0.17	1,489	325,000	0.34	2,978
2008	0.17	1,489	325,000	0.51	4,468
2009		0	0	0.51	4,468
2010		0	0	0.51	4,468
2011		0	0	0.51	4,468
2012		0	0	0.51	4,468
2013		0	0	0.51	4,468
2014		0	0	0.51	4,468

FinAnswer Express (formerly Retrofit Incentive, Sched. 115, 116)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005		0		0.00	0
2006	0.03	254	40,000	0.03	254
2007	0.07	613	100,000	0.10	867
2008	0.11	964	150,000	0.21	1,831
2009	0.11	964	150,000	0.32	2,794
2010	0.11	964	150,000	0.43	3,758
2011	0.11	964	150,000	0.54	4,722
2012	0.11	964	150,000	0.65	5,685
2013	0.11	964	150,000	0.76	6,649
2014	0.11	964	150,000	0.87	7,612

Residential Programs

Efficient Cooling, "Cool Cash or Coupons"

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005		0		0.00	0
2006		0	5,000	0.00	0
2007	0.02	131	30,000	0.02	131
2008	0.01	88	25,000	0.03	219
2009	0.01	88	25,000	0.04	307
2010	0.01	88	20,000	0.05	394
2011		0		0.05	394
2012		0		0.05	394
2013		0		0.05	394
2014		0		0.05	394

Washwise

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005				0.00	0
2006				0.00	0
2007	0.02	175	71,000	0.02	175
2008	0.02	160	65,000	0.04	336
2009				0.04	336
2010				0.04	336
2011				0.04	336
2012				0.04	336
2013				0.04	336
2014				0.04	336

Appliance Recycling, "See 'ya later refrigerator"

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005			0	0.00	0
2006	0.19	2,200	200,000	0.19	2,200
2007	0.25	2,200	260,000	0.44	4,400
2008	0.19	1,750	200,000	0.63	6,150
2009				0.63	6,150
2010				0.63	6,150
2011				0.63	6,150
2012				0.63	6,150
2013				0.63	6,150
2014				0.63	6,150

Low Income Weatherization

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.01	88	35,000	0.01	88
2006	0.03	219	100,000	0.04	307
2007	0.03	219	100,000	0.06	526
2008	0.03	219	100,000	0.09	745
2009	0.03	219	100,000	0.11	964
2010	0.03	219	100,000	0.14	1,183
2011	0.03	219	100,000	0.16	1,402
2012	0.03	219	100,000	0.19	1,621
2013	0.03	219	100,000	0.21	1,840
2014	0.03	219	100,000	0.24	2,059

New Construction

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005		0		0.00	0
2006		0	10,000	0.00	0
2007	0.01	123	65,000	0.01	123
2008	0.03	263	150,000	0.04	385
2009	0.03	263	150,000	0.07	648
2010	0.03	263	150,000	0.10	911
2011	0.02	175	100,000	0.12	1,086
2012		0		0.12	1,086
2013		0		0.12	1,086
2014		0		0.12	1,086

Table C.18 – Class 2 DSM Idaho (Continued)

Northwest Energy Efficiency Alliance

All Programs

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.44	3,854	352,000	0.44	3,854
2006	0.44	3,854	352,000	0.88	7,709
2007	0.44	3,854	352,000	1.32	11,563
2008	0.44	3,854	352,000	1.76	15,418
2009	0.44	3,854	352,000	2.20	19,272
2010		0		2.20	19,272
2011		0		2.20	19,272
2012		0		2.20	19,272
2013		0		2.20	19,272
2014		0		2.20	19,272

Idaho State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.61	5,344	562,000	0.61	5,344
2006	1.13	10,469	1,393,000	1.74	15,813
2007	1.94	17,039	2,708,000	3.69	32,852
2008	1.93	17,021	2,772,000	5.62	49,874
2009	1.56	13,622	2,182,000	7.18	63,496
2010	1.12	9,767	1,825,000	8.29	73,263
2011	1.10	9,592	1,755,000	9.39	82,855
2012	1.08	9,417	1,655,000	10.46	92,272
2013	1.08	9,417	1,655,000	11.54	101,689
2014	1.08	9,417	1,655,000	12.61	111,106

Oregon

Table C.19 – Class 2 DSM Oregon

Oregon State Total for Energy Trust

Calendar Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	9.60	84,096	0	9.60	84,096
2006	11.50	100,740	0	21.10	184,836
2007	11.00	96,360	0	32.10	281,196
2008	10.10	88,476	0	42.20	369,672
2009	10.20	89,352	0	52.40	459,024
2010	10.50	91,980	0	62.90	551,004
2011	10.60	92,856	0	73.50	643,860
2012	10.80	94,608	0	84.30	738,468
2013	1.70	14,892	0	86.00	753,360
2014	0.00	0	0	86.00	753,360

Utah

Table C.20 – Class 2 DSM Utah

Commercial and Industrial Programs

Energy FinAnswer (Sched. 125)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	3.67	32,149	5,500,000	3.67	32,149
2006	4.00	35,040	6,000,000	7.67	67,189
2007	4.67	40,909	7,000,000	12.34	108,098
2008	5.33	46,691	8,000,000	17.67	154,789
2009	5.33	46,691	8,000,000	23.00	201,480
2010	5.33	46,691	8,000,000	28.33	248,171
2011	5.33	46,691	8,000,000	33.66	294,862
2012	5.33	46,691	8,000,000	38.99	341,552
2013	5.33	46,691	8,000,000	44.32	388,243
2014	5.33	46,691	8,000,000	49.65	434,934

Retro Commissioning

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.00	0		0.00	0
2006	0.16	1,402	400,000	0.16	1,402
2007	0.22	1,927	550,000	0.38	3,329
2008	0.24	2,102	600,000	0.62	5,431
2009	0.28	2,453	700,000	0.90	7,884
2010	0.00			0.90	7,884
2011	0.00			0.90	7,884
2012	0.00			0.90	7,884
2013	0.00			0.90	7,884
2014	0.00				

FinAnswer Express (formerly Retrofit Incentive, Sched. 115, 116)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	1.50	13,140	2,150,000	1.50	13,140
2006	1.43	12,527	2,000,000	2.93	25,667
2007	1.57	13,753	2,200,000	4.50	39,420
2008	1.57	13,753	2,200,000	6.07	53,173
2009	1.57	13,753	2,200,000	7.64	66,926
2010	1.57	13,753	2,200,000	9.21	80,680
2011	1.57	13,753	2,200,000	10.78	94,433
2012	1.57	13,753	2,200,000	12.35	108,186
2013	1.57	13,753	2,200,000	13.92	121,939
2014	1.57	13,753	2,200,000	15.49	135,692

Self-Direction Credit projects (Sched. 192)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.90	7,884	300,000	0.90	7,884
2006	0.80	7,008	325,000	1.70	14,892
2007	0.90	7,884	360,000	2.60	22,776
2008	0.90	7,884	360,000	3.50	30,660
2009	0.90	7,884	360,000	4.40	38,544
2010	0.90	7,884	360,000	5.30	46,428
2011	0.90	7,884	360,000	6.20	54,312
2012	0.90	7,884	360,000	7.10	62,196
2013	0.90	7,884	360,000	8.00	70,080
2014	0.90	7,884	360,000	8.90	77,964

C&I Lighting Load Control 3%

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005					
2006	0.40	3,504	0	0.40	3,504
2007	0.90	7,884	0	1.30	11,388
2008	1.45	12,702	0	2.75	24,090
2009	1.45	12,702	0	4.20	36,792
2010	1.45	12,702	0	5.65	49,494
2011	1.45	12,702	0	7.10	62,196
2012	1.45	12,702	0	8.55	74,898
2013	1.45	12,702	0	10.00	87,600
2014	1.45	12,702	0	11.45	100,302

Table C.20 – Class 2 DSM Utah (Continued)

Residential Programs

Efficient Cooling, "Cool Cash"

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.40	3,504	2,900,000	0.40	3,504
2006	0.36	3,154	2,500,000	0.76	6,658
2007	0.36	3,154	2,500,000	1.12	9,811
2008	0.36	3,154	2,500,000	1.48	12,965
2009	0.11	964	750,000	1.59	13,928
2010	0.11	964	750,000	1.70	14,892
2011	0.11	964	750,000	1.81	15,856
2012	0.11	964	750,000	1.92	16,819
2013	0.11	964	750,000	2.03	17,783
2014	0.11	964	750,000	2.14	18,746

New Construction

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005		0		0.00	0
2006	0.35	3,066	1,610,000	0.35	3,066
2007	0.50	4,380	2,100,000	0.85	7,446
2008	0.50	4,380	2,100,000	1.35	11,826
2009	0.50	4,380	2,100,000	1.85	16,206
2010	0.50	4,380	2,100,000	2.35	20,586
2011				2.35	20,586
2012				2.35	20,586
2013				2.35	20,586
2014				2.35	20,586

Appliance Recycling, "See 'ya later refrigerator"

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	3.17	27,769	2,700,000	3.17	27,769
2006	2.50	21,900	2,550,000	5.67	49,669
2007	2.30	20,148	2,300,000	7.97	69,817
2008	2.00	17,520	2,000,000	9.97	87,337
2009	0.00	0		9.97	87,337
2010	0.00	0		9.97	87,337
2011	0.00	0		9.97	87,337
2012	0.00	0		9.97	87,337
2013	0.00	0		9.97	87,337
2014	0.00	0		9.97	87,337

Low Income Weatherization

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.02	175	50,000	0.02	175
2006	0.12	1,051	255,000	0.14	1,226
2007	0.12	1,051	255,000	0.26	2,278
2008	0.12	1,051	255,000	0.38	3,329
2009	0.12	1,051	255,000	0.50	4,380
2010	0.12	1,051	255,000	0.62	5,431
2011	0.12	1,051	255,000	0.74	6,482
2012	0.12	1,051	255,000	0.86	7,534
2013	0.12	1,051	255,000	0.98	8,585
2014	0.12	1,051	255,000	1.10	9,636

Utah State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	9.66	84,622	13,600,000	9.66	84,622
2006	10.12	88,651	15,640,000	19.78	173,273
2007	11.54	101,090	17,265,000	31.32	274,363
2008	12.47	109,237	18,015,000	43.79	383,600
2009	10.26	89,878	14,365,000	54.05	473,478
2010	9.98	87,425	13,665,000	64.03	560,903
2011	9.48	83,045	11,565,000	73.51	643,948
2012	9.48	83,045	11,565,000	82.99	726,992
2013	9.48	83,045	11,565,000	92.47	810,037
2014	9.48	83,045	11,565,000	101.05	885,198

Washington

Table C.21 – Class 2 DSM Washington

Commercial and Industrial Programs

Energy FinAnswer (Sched. 125)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	1.35	11826	2000000	1.35	11826
2006	2	17520	3000000	3.35	29346
2007	1.67	14629	2500000	5.02	43975.2
2008	1.67	14629	2500000	6.69	58604.4
2009	1.67	14629	2500000	8.36	73233.6
2010	1.67	14629	2500000	10.03	87862.8
2011	1.67	14629	2500000	11.7	102492
2012	1.67	14629	2500000	13.37	117121.2
2013	1.67	14629	2500000	15.04	131750.4
2014	1.67	14629	2500000	16.71	146379.6

FinAnswer Express (formerly Retrofit Incentive, Sched. 115,116)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.5	4380	750000	0.5	4380
2006	0.7	6132	985122	1.2	10512
2007	0.7	6132	985000	1.9	16644
2008	0.7	6132	985000	2.6	22776
2009	0.7	6132	850000	3.3	28908
2010	0.7	6132	850000	4	35040
2011	0.7	6132	850000	4.7	41172
2012	0.7	6132	850000	5.4	47304
2013	0.7	6132	850000	6.1	53436
2014	0.7	6132	850000	6.8	59568

Residential Programs

Efficient Cooling, "Cool Cash or Coupons"

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005		0	0	0.00	0
2006		0	10,000	0.00	0
2007	0.03	263	65,000	0.03	263
2008	0.03	219	50,000	0.06	482
2009	0.03	219	50,000	0.08	701
2010	0.03	219	50,000	0.11	920
2011		0		0.11	920
2012		0		0.11	920
2013		0		0.11	920
2014		0		0.11	920

Low Income Weatherization

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.08	701	1,041,733	0.08	701
2006	0.09	788	1,100,000	0.17	1,489
2007	0.09	788	1,100,000	0.26	2,278
2008	0.09	788	1,100,000	0.35	3,066
2009	0.09	788	1,100,000	0.44	3,854
2010	0.09	788	1,100,000	0.53	4,643
2011	0.09	788	1,100,000	0.62	5,431
2012	0.09	788	1,100,000	0.71	6,220
2013	0.09	788	1,100,000	0.80	7,008
2014	0.09	788	1,100,000	0.89	7,796

Appliance Recycling, "See 'ya later refrigerator"

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005			0	0.00	0
2006	0.51	4,468	510,000	0.51	4,468
2007	0.52	4,555	520,000	1.03	9,023
2008	0.40	3,504	400,000	1.43	12,527
2009				1.43	12,527
2010				1.43	12,527
2011				1.43	12,527
2012				1.43	12,527
2013				1.43	12,527
2014				1.43	12,527

New Construction

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005		0		0.00	0
2006	0.05	438	235,000	0.05	438
2007	0.06	526	285,000	0.11	964
2008	0.06	526	285,000	0.17	1,489
2009	0.06	526	285,000	0.23	2,015
2010	0.05	438	250,000	0.28	2,453
2011				0.28	2,453
2012				0.28	2,453
2013				0.28	2,453
2014				0.28	2,453

Do-it-Yourself Energy Audit (Paper or Web based)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.008	70	300,000	0.01	70.1
2006	0.008	70	300,000	0.0160	140.2
2007	0.007	61	250,000	0.0230	201.5
2008	0.007	61	250,000	0.0300	262.8
2009	0.007	61	200,000	0.0370	324.1
2010				0.0370	324.1
2011				0.0370	324.1
2012				0.0370	324.1
2013				0.0370	324.1
2014				0.0370	324.1

Energy Education Program

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.09	788	300,000	0.09	788
2006	0.10	876	335,000	0.19	1,664
2007	0.11	964	352,000	0.30	2,628
2008		0		0.30	2,628
2009		0		0.30	2,628
2010		0		0.30	2,628
2011		0		0.30	2,628
2012		0		0.30	2,628
2013		0		0.30	2,628
2014		0		0.30	2,628

Table C.21 – Class 2 DSM Washington (Continued)

Residential Programs - Continued

Washwise

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005					
2006	0.0354	310	126,000	0.0354	310.10
2007	0.0354	310	126,000	0.0708	620.21
2008				0.0708	620.21
2009				0.0708	620.21
2010				0.0708	620.21
2011				0.0708	620.21
2012				0.0708	620.21
2013				0.0708	620.21
2014				0.0708	620.21

Northwest Energy Efficiency Alliance

All Programs

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.56	4,906	448,000	0.56	4,906
2006	0.56	4,906	448,000	1.12	9,811
2007	0.56	4,906	448,000	1.68	14,717
2008	0.56	4,906	448,000	2.24	19,622
2009	0.56	4,906	448,000	2.80	24,528
2010				2.80	24,528
2011				2.80	24,528
2012				2.80	24,528
2013				2.80	24,528
2014				2.80	24,528

Washington State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	2.59	22,671	4,839,733	2.59	22,671
2006	4.05	35,508	7,049,122	6.64	58,179
2007	3.78	33,134	6,631,000	10.42	91,312
2008	3.51	30,765	6,018,000	13.94	122,078
2009	3.11	27,261	5,433,000	17.05	149,339
2010	2.54	22,207	4,750,000	19.58	171,545
2011	2.46	21,550	4,450,000	22.04	193,095
2012	2.46	21,550	4,450,000	24.50	214,645
2013	2.46	21,550	4,450,000	26.96	236,194
2014	2.46	21,550	4,450,000	29.42	257,744

Wyoming

Table C.22 – Class 2 DSM Wyoming

Commercial and Industrial Programs

Energy FinAnswer (Sched. 125)

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.10	876	75,000	0.10	876
2006	0.10	876	150,000	0.20	1,752
2007	0.10	876	150,000	0.30	2,628
2008	0.10	876	150,000	0.40	3,504
2009	0.10	876	150,000	0.50	4,380
2010	0.10	876	150,000	0.60	5,256
2011	0.10	876	150,000	0.70	6,132
2012	0.10	876	150,000	0.80	7,008
2013	0.10	876	150,000	0.90	7,884
2014	0.10	876	150,000	1.00	8,760

Residential Programs

Low Income Weatherization

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.01	88	80,000	0.010	88
2006	0.01	88	131,000	0.020	175
2007	0.01	88	131,000	0.030	263
2008	0.01	88	131,000	0.040	350
2009	0.01	88	131,000	0.050	438
2010	0.01	88	131,000	0.060	526
2011	0.01	88	131,000	0.070	613
2012	0.01	88	131,000	0.080	701
2013	0.01	88	131,000	0.090	788
2014	0.01	88	131,000	0.100	876

Wyoming State Total for PacifiCorp

Fiscal Year	MWa First Year	MWh First Year	Budget $	MWa Cumulative	MWh Cumulative
2005	0.11	964	155,000	0.11	964
2006	0.11	964	281,000	0.22	1,927
2007	0.11	964	281,000	0.33	2,891
2008	0.11	964	281,000	0.44	3,854
2009	0.11	964	281,000	0.55	4,818
2010	0.11	964	281,000	0.66	5,782
2011	0.11	964	281,000	0.77	6,745
2012	0.11	964	281,000	0.88	7,709
2013	0.11	964	281,000	0.99	8,672
2014	0.11	964	281,000	1.10	9,636

Front Office Transactions

For the 2004 IRP, PacifiCorp includes up to 1,200 MW of Front Office transactions in all portfolio simulations. These amounts are proxy resources that represent procurement activity expected to be made on an annual, rolling, forward basis to help cover PacifiCorp's short position, and are applied for all years of the planning horizon. The Company has reviewed historical operational data and, based upon this information, existing transmission constraints and institutional experience, arrived at the 1,200 MW level. For planning purposes, Front Office Transactions were priced at the forward market price curve used in the IRP.

The Front Office Transaction amounts include transactions for both the West and the East. The West includes 500 MW of annual 7x24. The East includes 500 MW of HLH products at Four Corners in Q3 and 200 MW of HLH products at Mona in Q3. As with any forward purchase, these resources will become a part of the overall portfolio for which balancing activities are routinely performed, such as selling off excess power during "shoulder" time periods.

The IRP process, when planning to the 15% margin, is attempting to add flexibility to the portfolio by including Front Office Transactions. The risk analysis for this flexibility has been captured by the stochastic portfolio analyses performed on the dispatchable Front Office Transactions. Given a stochastic distribution of market conditions, Front Office Transactions were dispatched within a portfolio and the resulting PVRRs were included in a risk analysis (see Chapter 8).

These transactions comport with the forward market view and environment of the current IRP. The IRP is a dynamic process influenced by numerous changing market variables. The addition of the Front Office Transactions offers flexibility and diversity to the portfolio, allowing the Company a degree of nimbleness in the short-term and medium-term markets.

Qualifying Facilities

As discussed in Chapter 3, PacifiCorp assumed that 100 MW of Qualifying Facility capacity would be available to serve Utah load on a dependable basis beginning in FY 2006. Similar to the way Front Office transactions are modeled, this QF capacity is included in all portfolios, and is applied for all years of the planning horizon. Pricing is based on the Utah PUC Stipulation regarding an IRP-Based Avoided Cost Methodology for QF Projects (Docket No. 03-035-14).

Hydroelectric Generation

Hydroelectric Relicensing Impacts on Generation

Table C.23 lists the estimated impacts to average annual hydro generation from FERC license renewals. PacifiCorp assumed that all hydroelectric facilities currently involved in the relicensing process will receive new operating licenses, but that additional operating restrictions on other requirements imposed in new licenses would reduce generation available from these facilities. These figures are estimates of these impacts.

Table C.23 – Hydroelectric Relicensing Impacts on Generation

Fiscal Year	Lost Generation MWh
2006	152,461
2007	152,214
2008	207,832
2009	255,435
2010	274,271
2011	304,317
2012	304,317
2013	304,317
2014	304,317
2015	304,317
2016	304,317
2017	304,317
2018	304,317
2019	304,317
2020	304,317
2021	304,317
2022	304,317
2023	304,317
2024	304,317
2025	304,317

Note: Excludes Condit, Powerdale and American Fork Decommissionings.

Hydroelectric Generation Existing Facilities

Table C.24 provides an operational profile for each of PacifiCorp's hydroelectric generation facilities. Dates are in calendar year.

Table C.24 – Hydroelectric Generation Facilities

Plant	PacifiCorp Share Net Rating (MW)	Location	Commercial Date	Current Age of Unit	Weighted Average Age of Plant	Power Supply Recommended Life	License Expiration Date	Power Supply Recommedation Year Ending Life	Years Remaining from 2004
Ashton	6.85	Idaho	1923	81	81	105	2028	2028	24
Bend	1.11	Oregon	1913	91	91	92	Unlicensed	2005	1
Big Fork	4.15	Montana	1924	80	80	107	2001	2031	27
Clearwater-1	15.00	Oregon	1953	51	51	87	1997	2040	36
Clearwater-2	26.00	Oregon	1953	51	51	87	1997	2040	36
Cline Falls	1.00	Oregon	1943	61	61	62	Unlicensed	2005	1
Condit	9.60	Washington	1913	91	91	91	1993	2006	2
Copco-1	20.00	California	1918	86	86	118	2006	2036	32
Copco-2	27.00	California	1925	79	79	100	2006	2025	21
Cove	7.50	Idaho	1917	87	87	114	2001	2031	27
Cutler	30.00	Utah	1927	77	77	97	2024	2024	20
Eagle Point	2.80	Oregon	1957	47	47	53	Unlicensed	2010	6
East Side	3.20	Oregon	1924	80	80	82	2006	2010	6
Fall Creek	2.20	California	1908	96	96	98	2006	2036	32
Fish Creek	11.00	Oregon	1952	52	52	88	1997	2040	36
Fountain Green	0.16	Utah	1922	82	82	88	Exempt	2010	6
Grace	33.00	Idaho	1923	81	81	108	2001	2031	27
Granite	2.00	Utah	1896	108	108	134	Unlicensed	2030	26
Gunlock	0.75	Utah	1917	87	87	103	Exempt	2020	16
Iron Gate	18.00	California	1962	42	42	74	2006	2036	32
JC Boyle	80.00	Oregon	1958	46	46	78	2006	2036	32
Last Chance	1.70	Idaho	1984	20	20	41	Exempt	2025	21
Lemolo-1	29.00	Oregon	1955	49	49	85	1997	2040	36
Lemolo-2	33.00	Oregon	1956	48	48	84	1997	2040	36
Merwin	136.00	Washington	1932	72	72	104	2009	2036	32
Naches	6.37	Washington	1909	95	95	97	Unlicensed	2006	2
Naches Drop	1.40	Washington	1915	89	89	91	Unlicensed	2006	2
Onieda	30.00	Idaho	1915	89	89	116	2001	2031	27
Paris	0.70	Idaho	1910	94	94	105	Exempt	2015	11
Pioneer	5.00	Utah	1914	90	90	116	2000	2030	26
Powerdale	6.00	Oregon	1923	81	81	95	2000	2018	14
Prospect-1, 2 & 4	36.76	Oregon	1912	92	92	123	2005	2035	31
Prospect-3	7.20	Oregon	1932	72	72	87	2019	2019	15
Sand Cove	0.80	Utah	1920	84	84	100	Exempt	2020	16
Skookumchuck	0.48	Washington	1990	14	14	58	Exempt	2048	44
Slide Creek	18.00	Oregon	1951	53	53	89	1997	2040	36
Snake Creek	1.18	Utah	1910	94	94	110	Unlicensed	2020	16
Soda	14.00	Idaho	1924	80	80	107	2001	2031	27
Soda Springs	11.00	Oregon	1952	52	52	88	1997	2040	36
St. Anthony	0.50	Idaho	1915	89	89	113	2028	2004	0
Stairs	1.00	Utah	1914	90	90	111	2000	2025	21
Swift-1	240.00	Washington	1958	46	46	78	2006	2036	32
Toketee	42.50	Oregon	1939	65	65	101	1997	2040	36
Upper American Fork	0.95	Utah	1907	97	97	66	2000	2006	2
Upper Beaver	2.52	Utah	1907	97	97	123	Exempt	2030	26
Veyo	0.50	Utah	1920	84	84	100	Exempt	2020	16
Viva Naughton	0.74	Wyoming	1986	18	18	54	Exempt	2040	36
Wallowa Falls	1.10	Oregon	1921	83	83	95	2016	2016	12
Weber	3.85	Utah	1949	55	55	71	2020	2020	16
West Side	0.60	Oregon	1908	96	96	98	2006	2010	6
Yale	134.00	Washington	1953	51	51	73	2001	2026	22
	1,068.17								
The following are associated with and support PacifiCorp's Hydro facilities, but do not have generation									
Keno Regulating Dam								2036	32
Klamath Lake Reservoir								2036	32
Lifton								2048	44
North Umpqua General								2040	36
The following is operated by PacifiCorp, but is owned by others									
Olmsted	10.30							2016	12

Thermal Resources

Table C.25 lists operational profile information for the PacifiCorp thermal resources, including plant type, maximum MW capacity, ownership share, location, retirement date, and FERC Form 1 heat rates. Currant Creek and Lake Side are approximate heat rates based on design expectations.

Table C.25 – Thermal Generation Facilities

Thermal Plant	Thermal Type	Maximum (MW)	PacifiCorp Share	State	Retirement Date (CY)	Heat Rate (BTUs/kWh)
Blundell	Geothermal	23	100%	Utah	2021	--
Carbon 1	Coal	67	100%	Utah	2020	11,346
Carbon 2	Coal	105	100%	Utah	2020	11,346
Cholla 4	Coal	380	100%	Arizona	2025	10,493
Colstrip 3	Coal	74	10%	Montana	2029	10,838
Colstrip 4	Coal	74	10%	Montana	2029	10,838
Craig 1	Coal	83	19%	Colorado	2024	10,355
Craig 2	Coal	83	19%	Colorado	2024	10,355
Currant Creek	Gas	525	100%	Utah	2040	7,462
Dave Johnston 1	Coal	106	100%	Wyoming	2020	11,123
Dave Johnston 2	Coal	106	100%	Wyoming	2020	11,123
Dave Johnston 3	Coal	220	100%	Wyoming	2020	11,123
Dave Johnston 4	Coal	330	100%	Wyoming	2020	11,123
Gadsby 1	Gas	60	100%	Utah	2017	13,495
Gadsby 2	Gas	75	100%	Utah	2017	13,495
Gadsby 3	Gas	100	100%	Utah	2017	13,495
Gadsby 4	Gas	40	100%	Utah	2027	10,695
Gadsby 5	Gas	40	100%	Utah	2027	10,695
Gadsby 6	Gas	40	100%	Utah	2027	10,695
Hayden 1	Coal	45	24%	Colorado	2024	10,523
Hayden 2	Coal	33	13%	Colorado	2024	10,523
Hermiston 1	Gas	119	50%	Oregon	2031	7,166
Hermiston 2	Gas	119	50%	Oregon	2031	7,166
Hunter 1	Coal	403	94%	Utah	2025	10,471
Hunter 2	Coal	259	60%	Utah	2025	10,471
Hunter 3	Coal	460	100%	Utah	2025	10,471
Huntington 1	Coal	445	100%	Utah	2019	10,112
Huntington 2	Coal	450	100%	Utah	2019	10,112
Jim Bridger 1	Coal	353	67%	Wyoming	2020	10,591
Jim Bridger 2	Coal	353	67%	Wyoming	2020	10,591
Jim Bridger 3	Coal	353	67%	Wyoming	2020	10,591
Jim Bridger 4	Coal	353	67%	Wyoming	2020	10,591
Lake Side	Gas	534	100%	Utah	2043	7,186
Little Mountain	Gas	14	100%	Utah	2006	16,574
Naughton 1	Coal	160	100%	Wyoming	2022	10,661
Naughton 2	Coal	210	100%	Wyoming	2022	10,661
Naughton 3	Coal	330	100%	Wyoming	2022	10,661
West Valley 1	Gas	40	100%	Utah	2017	9,878
West Valley 2	Gas	40	100%	Utah	2017	9,878
West Valley 3	Gas	40	100%	Utah	2017	9,878
West Valley 4	Gas	40	100%	Utah	2017	9,878
West Valley 5	Gas	40	100%	Utah	2017	9,878
Wyodak	Coal	268	80%	Wyoming	2022	12,172
Other Plant						
Foote Creek	Wind	33	79%	Wyoming	2024	--

Notes

1) Maximum (MW) represent PacifiCorp share of the plant.

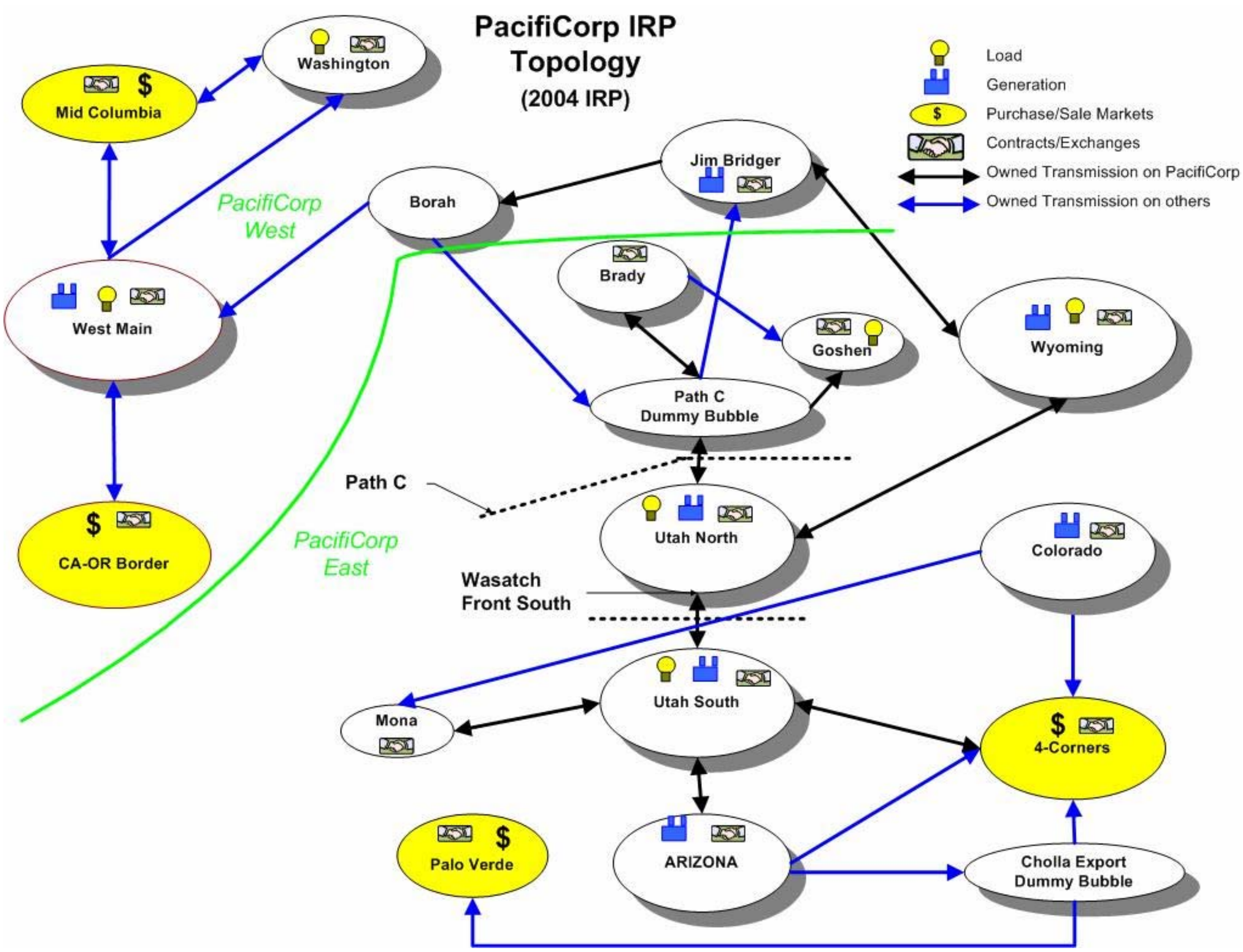
2) Plant lives are currently being reviewed for compliance with future environmental regulations.

Transmission System

System Topology

PacifiCorp uses a transmission topology consisting of 18 bubbles (geographical areas) designed to best 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 transfer capabilities between the bubbles represent PacifiCorp Merchant function's firm rights on the transmission lines. Figure C.5 shows the IRP transmission topology.

Figure C.5 – IRP Transmission Topology



Transmission Modeling Approach

All portfolios are modeled using MARKETSYM's transport logic technique. The transport logic identifies energy trading opportunities and the contract path (minimum-cost path), and schedules power flow to maximize revenue subject to PacifiCorp's transfer capability assumptions discussed earlier. See Appendix H, "Model Descriptions", for more details concerning how the PacifiCorp transmission system is represented and modeled using MARKETSYM.

Transmission Losses

Transmission losses are netted in the loads as stipulated in FERC form 714 (4.48% real loss rate, schedule 9).

Congestion Charges

Transmission charges associated with a congestion pricing regime are not modeled. A detailed analysis of the impacts of congestion pricing will be undertaken in a future IRP when details concerning such pricing become available.

NEW RESOURCES

Demand Side Management

Class 1 Programs

Table C.26 provides an overview of Class 1 DSM programs that were evaluated in the 2004 IRP analysis. These proxies for modeling were developed based on the 2003 DSM RFP proposals as well as existing program experience, however don't necessarily represent market potential. Loads shown are at the generator (grossed up for line losses).

Table C.26 – Potential Class 1 DSM Programs

Name	Location	Maximum Program (MW)	Program Cost, $/kW-yr
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

Class 2 Programs

The following plots illustrate the hourly end use shapes used for the Class 2 DSM decrement analysis. Figure C.6 plots the hourly end use shapes for the peak day use for each of the six end uses. The MW scale on the y –axis of Figures C.6 and C.7 is for illustration purposes only and does not represent the market potential or planning estimates of any particular program for a given end use. For example, the commercial cooling shape was created from system specific weighting of hospital, school, office, lodging, and service cooling end use shapes. Figure C.7 illustrates the seasonality of the end uses by plotting peak demand for each week. The east residential cooling shape was derived from an in-house metering study. All other shapes are composites of end use patterns from the Northwest Power Planning and Conservation Council.

Figure C.6 – DSM Decrement, Daily End Use Shape

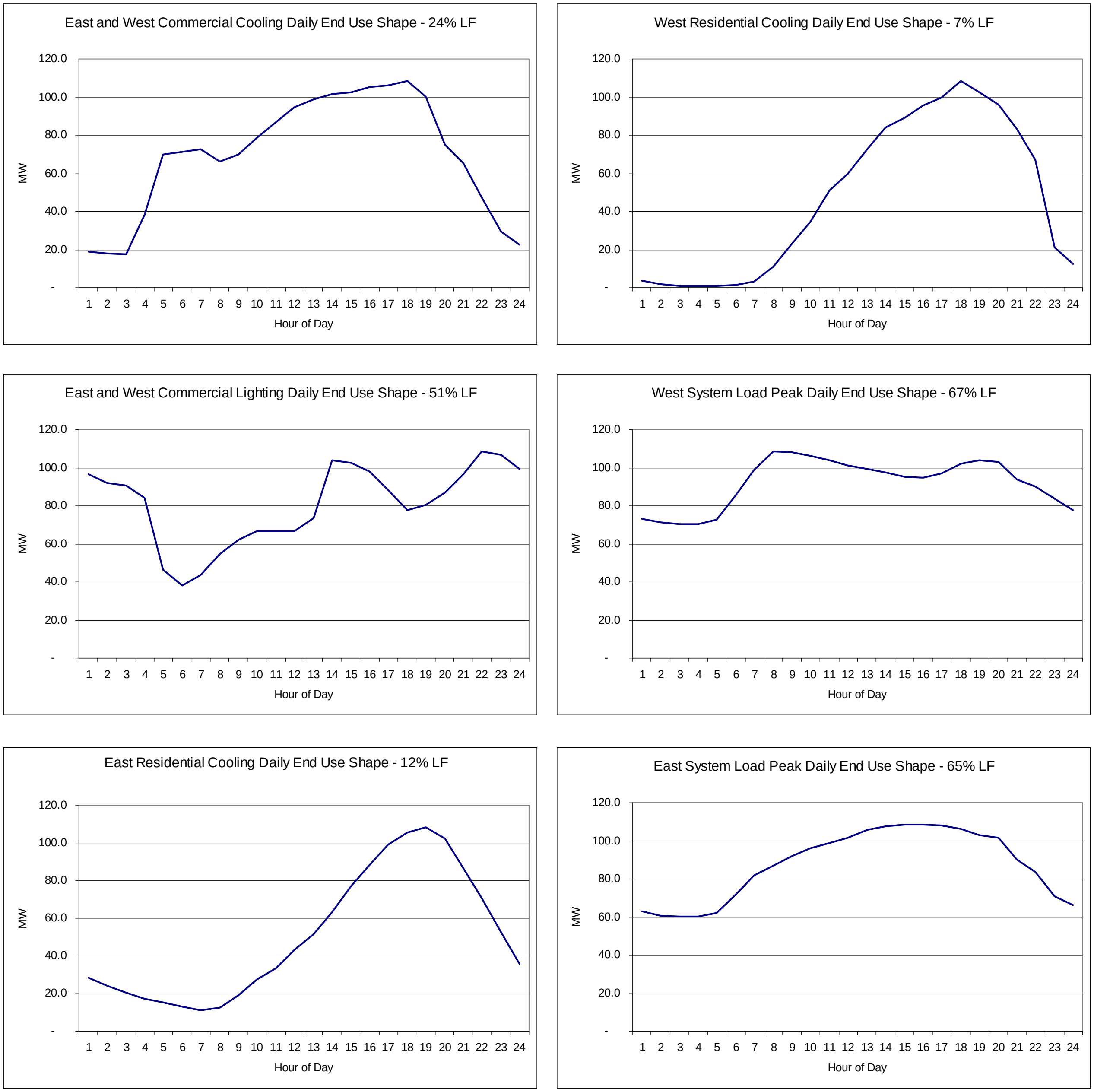
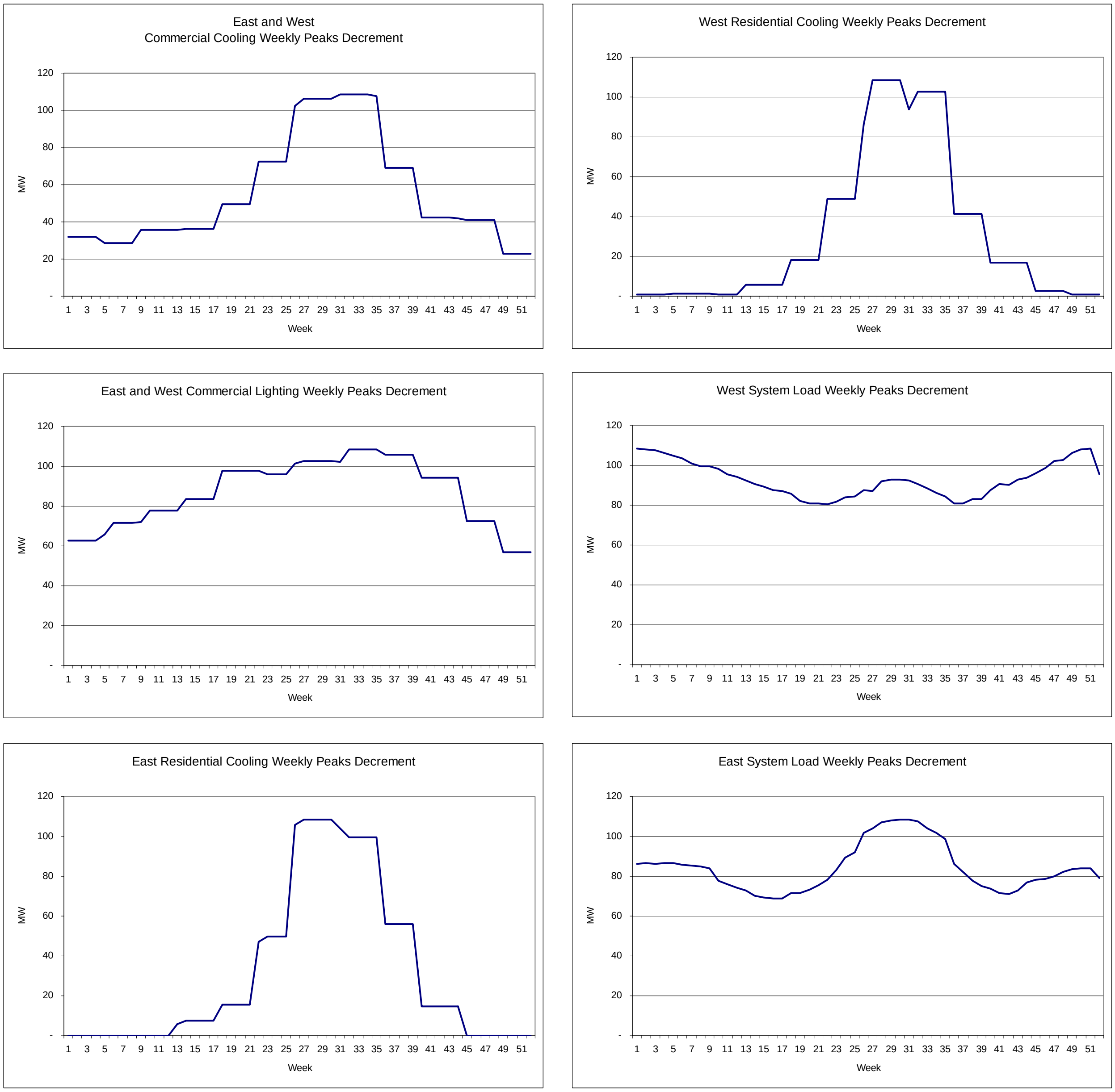


Figure C.7 – DSM Decrement, Weekly Peaks



Supply Side Options

Tables C.27 and C.28 show plant cost and technology information for each resource considered for inclusion into a portfolio. Costs and performance reflect assumptions as of July 2004. Notes for table entries are located after Table C.28.

Table C.27 – Supply Side Options (East)

Description	Average Cap. (MW)	MWs Avail.	1st Year Avail. (FY)	Approximate Location	Design Plant Life in Years	Planning Margin Contribution	Forced Outage Rate	Maint. Outage Rate	Annual Heat Rate BTU/kWh	Emissions SO2 (lbs/MMBTU (Hg: lbs/Tbtu))	NOx	Hg	CO2	Capital Cost-$/kW Unit Cost
East Side Options														
Coal														
PC Subcritical *	575	91%	2011	Utah	40	100%	4%	5%	9,483	0.059	0.072	0.600	205.35	$ 1,687
PC Supercritical	575	91%	2011	Utah	40	100%	4%	5%	9,129	0.059	0.072	0.600	205.35	$ 1,735
Greenfield PC	575	91%	2012	Utah	40	100%	4%	5%	9,483	0.059	0.072	0.600	205.35	$ 1,729
Greenfield IGCC *	368	75%	2012	East	40	100%	10%	15%	8,311	0.030	0.050	0.600	205.35	$ 2,171
Brownfield PC *	575	91%	2012	Wyoming	40	100%	4%	5%	9,483	0.059	0.072	1.500	210.05	$ 1,813
Natural Gas														
Microturbines	0.20	98%	2008	Utah	15	100%	1%	1%	14,321	0.001	0.101	0.255	118.00	$ 2,370
Fuel Cells	2.25	98%	2008	Utah	25	100%	1%	1%	5,688	0.001	0.004	0.255	118.00	$ 1,538
Greenfield SCCT Aero	80	90%	2009	Utah	25	100%	5%	5%	10,225	0.001	0.018	0.255	118.00	$ 682
Greenfield Intercooled Aero SCCT *	87	90%	2009	Utah	25	100%	5%	5%	8,907	0.001	0.011	0.255	118.00	$ 590
Greenfield Internal Combustion Engines	165	92%	2009	Utah	25	100%	3%	5%	8,700	0.001	0.020	0.255	118.00	$ 633
Brownfield CCCT (Dry Cooling, 2x1) *	420	92%	2009	Utah	35	100%	3%	5%	7,462	-	0.011	0.255	118.00	$ 682
Brownfield CCCT Duct Firing for Dry Cooling 2x1 *	105	92%	2009	Utah	35	100%	3%	5%	9,512	-	0.011	0.255	118.00	$ 207
Greenfield CCCT - (Wet Cooling, 2x1) *	450	92%	2010	Utah	35	100%	3%	5%	7,186	0.001	0.011	0.255	118.00	$ 730
Greenfield CCCT - (Wet Cooling, 1x1)	211	92%	2010	Utah	35	100%	3%	5%	7,246	0.001	0.011	0.255	118.00	$ 815
Greenfield CCCT Duct Firing for Wet Cooling 2x1 or 1x1 *	110	92%	2010	Utah	35	100%	3%	5%	8,868	0.001	0.011	0.255	118.00	$ 186
Greenfield CCCT - (Dry Cooling, 2x1)	420	92%	2010	Utah	35	100%	3%	5%	7,462	0.001	0.011	0.255	118.00	$ 789
Greenfield CCCT - Duct Firing (Dry Cooling, 2x1)	105	92%	2010	Utah	35	100%	3%	5%	9,512	0.001	0.011	0.255	118.00	$ 207
Greenfield SCCT Frame - (2 Frame "F")	281	92%	2009	Utah	35	100%	3%	5%	11,052	0.001	0.032	0.255	118.00	$ 408
Other - Renewables														
Wind *	50	N/A	2008	Wyoming	20	20%	N/A	N/A	N/A	-	-	-	-	$ 1,256
Geothermal	30	97%	2009	Utah	35	100%	1%	3%	N/A	-	-	-	-	$ 1,650
Pumped Storage	200	N/A	2010	Utah	35	100%	N/A	N/A	13,924	0.017	0.020	0.168	57.50	$ 871
Compressed Air Energy Storage (CAES)	323	92%	2010	Wyoming	25	100%	3%	5%	12,363	0.001	0.011	0.255	118.00	$ 799
Customer Owned Standby Generation **	22	100%	2006	East	20	100%	N/A	N/A	10,500	N/A	N/A	N/A	N/A	$ 135
Solar	200	N/A	2011	Utah	35	67%	N/A	N/A	N/A	-	-	-	-	$ 5,153

Table C.27 – Supply Side Options (West)

Description	Average Cap. (MW)	MWs Avail.	1st Year Avail. (FY)	Approximate Location	Design Plant Life in Years	Planning Margin Contribution	Forced Outage Rate	Maint. Outage Rate	Annual Heat Rate BTU/kWh	Emissions SO2 lbs/MMBTU (Hg: lbs/Tbtu)	NOx	Hg	CO2	Capital Cost-$/kW Unit Cost
West Side Options (1500')														
Natural Gas														
Microturbines	0.23	98%	2008	Northwest	15	100%	1%	1%	14,321	0.001	0.101	0.255	118.00	$ 2,120
Fuel Cells	2.25	98%	2008	Northwest	25	100%	1%	1%	5,688	0.001	0.004	0.255	118.00	$ 1,538
Greenfield SCCT Aero	89	90%	2009	Northwest	25	100%	5%	5%	10,225	0.001	0.018	0.255	118.00	$ 595
Greenfield Intercooled Aero SCCT *	97	90%	2009	Northwest	25	100%	5%	5%	8,907	0.001	0.011	0.255	118.00	$ 528
Greenfield SCCT Frame (2 Frame "F")	315	92%	2009	Northwest	35	100%	3%	5%	11,052	0.001	0.032	0.255	118.00	$ 365
Greenfield Internal Combustion Engines	165	92%	2009	Northwest	25	100%	3%	5%	8,700	0.001	0.020	0.255	118.00	$ 633
Greenfield CCCT - (Wet Cooling, 2x1)	503	92%	2010	Northwest	35	100%	3%	5%	7,186	0.001	0.011	0.255	118.00	$ 653
Greenfield CCCT Duct Firing for Wet Cooling 2x1	123	92%	2010	Northwest	35	100%	3%	5%	8,868	0.001	0.011	0.255	118.00	$ 167
Greenfield CCCT - (Dry Cooling, 2x1) *	469	92%	2010	Northwest	35	100%	3%	5%	7,462	0.001	0.011	0.255	118.00	$ 706
Greenfield CCCT Duct Firing for Dry Cooling 2x1 *	117	92%	2010	Northwest	35	100%	3%	5%	9,512	0.001	0.011	0.255	118.00	$ 185
Other - Renewables														
Wind	50	n/a	2008	Northwest	20	20%	5%	n/a	n/a	-	-	-	-	$ 1,251
Geothermal	40	94%	2009	Northwest	35	100%	2%	5%	n/a	-	-	-	-	$ 2,310
Compressed Air Energy Storage (CAES)	361	92%	2010	Northwest	25	100%	3%	5%	12,363	0.001	0.018	0.255	118.00	$ 715
West Side Options (Sea Level)														
Natural Gas														
Microturbines	0.24	98%	2008	Northwest	15	100%	1%	1%	14,321	0.001	0.101	0.255	118.00	$ 2,014
Fuel Cells	2.25	98%	2008	Northwest	25	100%	1%	1%	5,688	0.001	0.004	0.255	118.00	$ 1,538
Greenfield SCCT Aero	94	90%	2009	Northwest	25	100%	5%	5%	10,225	0.001	0.018	0.255	118.00	$ 566
Greenfield Intercooled Aero SCCT	102	90%	2009	Northwest	25	100%	5%	5%	8,907	0.001	0.011	0.255	118.00	$ 502
Greenfield SCCT Frame (2 Frame "F")	331	92%	2009	Northwest	35	100%	3%	5%	11,052	0.001	0.032	0.255	118.00	$ 347
Greenfield Internal Combustion Engines	165	92%	2009	Northwest	25	100%	3%	5%	8,700	0.001	0.020	0.255	118.00	$ 633
Greenfield CCCT - (Wet Cooling, 2x1)	529	92%	2009	Northwest	35	100%	3%	5%	7,186	0.001	0.011	0.255	118.00	$ 620
Greenfield CCCT Duct Firing for Wet Cooling 2x1	129	92%	2010	Northwest	35	100%	3%	5%	8,868	0.001	0.011	0.255	118.00	$ 158
Greenfield CCCT - (Dry Cooling, 2x1)	494	92%	2010	Northwest	35	100%	3%	5%	7,462	0.001	0.011	0.255	118.00	$ 670
Greenfield CCCT Duct Firing for Dry Cooling 2x1	124	92%	2010	Northwest	35	100%	3%	5%	9,512	0.001	0.011	0.255	118.00	$ 176
Other- Renewables														
Wind	50	N/A	2008	Northwest	20	20%	5%	N/A	N/A	-	-	-	-	$ 1,251
Combine Heat and Power (CHP)	45	85%	2006	Northwest	20	100%	5%	10%	9,220	0.001	0.087	0.255	117.00	$ 630
Customer Owned Standby Generation **	22	100%	2006	Northwest	10	100%	N/A	N/A	10,500	N/A	N/A	N/A	N/A	$ 135
Compressed Air Energy Storage (CAES)	380	92%	2008	Northwest	25	100%	3%	5%	12,363	0.001	0.018	0.255	118.00	$ 679

Table C.28 – Supply Side Options – Resource Cost Sheet (East)

	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs mills/kWh				Total
Description	Total Cap Cost	Payment Factor	Annual Pmt $/kW-Yr	Fixed O&M $/kW-Yr O&M	Other	Total	Total Fixed $/kW-Yr	Capacity Factor	Total Fixed Mills/kWh	Levelized Fuel ¢/mmBtu	Mills/kWh	O&M	Fuel/Other	Environmental	Tax Credits	Resource Cost (Mills/kWh)
East Side Options																
Coal																
PC Subcritical *	$ 1,687	7.53%	$ 127.00	$ 32.23	$ 5.00	$ 37.23	$ 164.23	91%	20.60	91.47	8.40	$ 0.80	-	5.71	-	35.51
PC Supercritical	$ 1,735	7.53%	$ 130.61	$ 33.77	$ 5.00	$ 38.77	$ 169.37	91%	21.25	91.47	8.08	$ 0.78	-	5.49	-	35.60
Greenfield PC	$ 1,729	7.53%	$ 130.20	$ 38.78	$ 5.00	$ 43.78	$ 173.98	91%	21.82	91.47	8.40	$ 0.80	-	5.71	-	36.73
Greenfield IGCC *	$ 2,171	7.53%	$ 163.47	$ 30.52	$ 5.00	$ 35.52	$ 198.99	75%	30.29	91.47	7.36	$ 1.83	-	4.79	-	44.27
Brownfield PC *	$ 1,813	7.53%	$ 136.55	$ 38.78	$ 5.00	$ 43.78	$ 180.33	91%	22.62	110.93	10.52	$ 0.80	-	6.04	-	39.98
Natural Gas																
Microturbines	$ 2,370	11.15%	$ 264.20	$ 444.08	-	$ 444.08	$ 708.28	98%	82.50	381.43	58.80	$ 8.13	6.13	5.32	-	160.88
Fuel Cells	$ 1,538	8.22%	$ 126.34	$ 55.12	$ 5.00	$ 60.12	$ 186.46	98%	21.72	381.43	21.70	$ 2.18	2.44	-	-	48.04
Greenfield SCCT Aero	$ 682	8.98%	$ 61.23	$ 13.01	$ 1.35	$ 14.36	$ 75.59	16%	53.93	381.43	41.99	$ 4.00	4.38	3.23	-	107.53
Greenfield Intercooled Aero SCCT *	$ 590	8.98%	$ 52.97	$ 6.76	$ 1.35	$ 8.11	$ 61.08	16%	43.58	381.43	36.58	$ 4.44	3.81	2.77	-	91.18
Greenfield Internal Combustion Engines	$ 633	8.98%	$ 56.85	$ 12.72	$ 1.35	$ 14.07	$ 70.92	92%	8.80	381.43	33.18	$ 5.50	3.72	-	2.76	53.97
Brownfield CCCT (Dry Cooling, 2x1) *	$ 682	7.93%	$ 54.07	$ 4.66	$ 1.35	$ 6.01	$ 60.08	56%	12.25	381.43	30.64	$ 3.18	3.19	2.32	-	51.58
Brownfield CCCT Duct Firing for Dry Cooling 2x1 *	$ 207	7.93%	$ 16.41	$ 2.93	$ 1.35	$ 4.28	$ 20.69	16%	14.76	381.43	39.06	$ 0.10	4.07	2.96	-	60.95
Greenfield CCCT - (Wet Cooling, 2x1) *	$ 730	7.93%	$ 57.87	$ 8.85	$ 1.35	$ 10.20	$ 68.07	56%	13.88	381.43	29.51	$ 3.17	3.08	2.24	-	51.86
Greenfield CCCT - (Wet Cooling, 1x1)	$ 815	7.93%	$ 64.60	$ 13.14	$ 1.35	$ 14.49	$ 79.09	56%	16.12	381.43	29.75	$ 3.17	3.10	2.25	-	54.40
Greenfield CCCT Duct Firing for Wet Cooling 2x1 or 1x1 *	$ 186	7.93%	$ 14.77	$ 2.80	$ 1.35	$ 4.15	$ 18.92	16%	13.50	381.43	36.41	$ 0.10	3.80	2.76	-	56.57
Greenfield CCCT - (Dry Cooling, 2x1)	$ 789	7.93%	$ 62.54	$ 10.63	$ 1.35	$ 11.98	$ 74.52	56%	15.19	381.43	30.64	$ 3.27	3.19	2.32	-	54.62
Greenfield CCCT - Duct Firing (Dry Cooling, 2x1)	$ 207	7.93%	$ 16.41	$ 2.93	$ 1.35	$ 4.28	$ 20.69	16%	14.76	381.43	39.06	$ 0.10	4.07	2.96	-	60.95
Greenfield SCCT Frame - (2 Frame "F")	$ 408	7.67%	$ 31.31	$ 10.97	$ 1.35	$ 12.32	$ 43.62	16%	31.12	381.43	42.16	$ 5.35	4.73	-	3.60	86.96
Other - Renewables																
Wind *	$ 1,256	9.10%	$ 114.25	$ 40.63	$ 0.50	$ 41.13	$ 155.37	35%	50.68	-	-	-	4.64		(11.01)	44.31
Geothermal	$ 1,650	6.87%	$ 113.40	$ 80.17	$ 1.35	$ 81.52	$ 194.92	97%	23.06	-	17.00	$ 2.34	-		(7.08)	35.31
Pumped Storage	$ 871	7.93%	$ 69.07	$ 10.25	$ 1.35	$ 11.60	$ 80.67	16%	57.56	-	35.71	$ 0.52	-	0.66	-	94.45
Compressed Air Energy Storage (CAES)	$ 799	9.29%	$ 74.21	$ 5.53	$ 1.35	$ 6.88	$ 81.09	25%	37.03	-	35.71	$ 1.41	-	3.85	-	77.99
Customer Owned Standby Generation **	$ 135	15.34%	$ 19.93	-	-	-	$ 19.93	2%	98.90	633.45	66.51	$ 20.00	-	-	-	185.41
Solar	$ 5,153	6.87%	$ 354.20	$ 42.21	-	$ 42.21	$ 396.41	63%	71.83	-	-	$ 0.21	-		-	72.03

Table C.28 – Supply Side Options – Resource Cost Sheet (West)

	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs mills/kWh				Total
	Total	Payment	Annual Pmt	Fixed O&M $/kW-Yr			Total Fixed	Capacity	Total Fixed	Levelized Fuel						Resource Cost
Description	Cap Cost	Factor	$/kW-Yr	O&M	Other	Total	$/kW-Yr	Factor	Mills/kWh	¢/mmBtu	Mills/kWh	O&M	Fuel/Other	Environmental	Tax Credits	(Mills/kWh)
West Side Options (1500')														-		
Natural Gas														-		
Microturbines	$ 2,120	11.15%	$ 236.39	$ 397.34	-	$ 397.34	$ 633.73	98%	73.82	393.11	60.62	$ 7.27	5.99	5.32	-	153.02
Fuel Cells	$ 1,538	8.22%	$ 126.34	$ 55.12	$ 5.00	$ 60.12	$ 186.46	98%	21.72	393.11	22.36	$ 2.18	2.38	-	1.74	50.39
Greenfield SCCT Aero	$ 595	8.98%	$ 53.45	$ 11.64	$ 1.35	$ 12.99	$ 66.44	16%	47.40	393.11	43.28	$ 3.58	4.28	3.23	-	101.77
Greenfield Intercooled Aero SCCT *	$ 528	8.98%	$ 47.39	$ 6.05	$ 1.35	$ 7.40	$ 54.80	16%	39.10	393.11	37.70	$ 3.98	3.73	2.77	-	87.27
Greenfield SCCT Frame (2 Frame "F")	$ 365	7.67%	$ 28.01	$ 11.42	$ 1.35	$ 12.77	$ 40.78	16%	29.10	393.11	43.45	$ 4.79	4.62	-	3.60	85.55
Greenfield Internal Combustion Engines	$ 633	8.98%	$ 56.85	$ 12.72	$ 1.35	$ 14.07	$ 70.92	92%	8.80	393.11	36.82	$ 5.50	3.64	2.76	-	57.52
Greenfield CCCT - (Wet Cooling, 2x1)	$ 653	7.93%	$ 51.78	$ 9.51	$ 1.35	$ 10.86	$ 62.64	62%	11.53	393.11	30.42	$ 2.83	3.01	2.24	-	50.03
Greenfield CCCT Duct Firing for Wet Cooling 2x1	$ 167	7.93%	$ 13.22	$ 2.50	$ 1.35	$ 3.85	$ 17.07	16%	12.18	393.11	37.54	$ 0.10	3.71	2.76	-	56.29
Greenfield CCCT - (Dry Cooling, 2x1) *	$ 706	7.93%	$ 55.95	$ 9.51	$ 1.35	$ 10.86	$ 66.82	62%	12.30	393.11	31.58	$ 2.93	3.12	2.32	-	52.26
Greenfield CCCT Duct Firing for Dry Cooling 2x1 *	$ 185	7.93%	$ 14.68	$ 2.62	$ 1.35	$ 3.97	$ 18.65	16%	13.31	393.11	40.26	$ 0.10	3.98	2.96	-	60.61
Other - Renewables																
Wind	$ 1,251	9.10%	$ 113.75	$ 29.56	$ 0.50	$ 30.06	$ 143.81	34%	48.28	-	-	-	4.64	-	(11.01)	41.92
Geothermal	$ 2,310	6.87%	$ 158.77	$ 93.47	$ 1.35	$ 94.82	$ 253.59	94%	30.96	-	17.00	$ 2.34	-	-	(7.08)	43.22
Compressed Air Energy Storage (CAES)	$ 715	9.29%	$ 66.40	$ 4.95	$ 1.35	$ 6.30	$ 72.70	25%	33.20	-	35.71	$ 1.26	-	3.91	-	74.07
West Side Options (Sea Level)																
Natural Gas																
Microturbines	$ 2,014	11.15%	$ 224.57	$ 377.47	-	$ 377.47	$ 602.04	98%	70.13	393.11	60.62	$ 6.91	5.99	5.32	-	148.96
Fuel Cells	$ 1,538	8.22%	$ 126.34	$ 55.12	$ 5.00	$ 60.12	$ 186.46	98%	21.72	393.11	22.36	$ 2.18	2.38	-	1.74	50.39
Greenfield SCCT Aero	$ 566	8.98%	$ 50.78	$ 11.06	$ 1.35	$ 12.41	$ 63.19	16%	45.08	393.11	43.28	$ 3.40	4.28	3.23	-	99.27
Greenfield Intercooled Aero SCCT	$ 502	8.98%	$ 45.02	$ 5.75	$ 1.35	$ 7.10	$ 52.12	16%	37.19	393.11	37.70	$ 3.78	3.73	2.77	-	85.17
Greenfield SCCT Frame (2 Frame "F")	$ 347	7.67%	$ 26.61	$ 10.85	$ 1.35	$ 12.20	$ 38.81	16%	27.69	393.11	43.45	$ 4.55	4.62	-	3.60	83.91
Greenfield Internal Combustion Engines	$ 633	8.98%	$ 56.85	$ 12.72	$ 1.35	$ 14.07	$ 70.92	92%	8.80	393.11	36.82	$ 5.50	3.64	2.76	-	57.52
Greenfield CCCT - (Wet Cooling, 2x1)	$ 620	7.93%	$ 49.19	$ 9.04	$ 1.35	$ 10.39	$ 59.58	62%	10.97	393.11	30.42	$ 2.69	3.01	2.24	-	49.32
Greenfield CCCT Duct Firing for Wet Cooling 2x1	$ 158	7.93%	$ 12.56	$ 2.38	$ 1.35	$ 3.73	$ 16.28	16%	11.62	393.11	37.54	$ 0.10	3.71	2.76	-	55.73
Greenfield CCCT - (Dry Cooling, 2x1)	$ 670	7.93%	$ 53.16	$ 9.04	$ 1.35	$ 10.39	$ 63.54	62%	11.70	393.11	31.58	$ 2.78	3.12	2.32	-	51.51
Greenfield CCCT Duct Firing for Dry Cooling 2x1	$ 176	7.93%	$ 13.95	$ 2.49	$ 1.35	$ 3.84	$ 17.79	16%	12.69	393.11	40.26	$ 0.10	3.98	2.96	-	59.99
Other- Renewables																
Wind	$ 1,251	9.10%	$ 113.75	$ 29.56	$ 0.50	$ 30.06	$ 143.81	34%	48.28	-	-	-	4.64	-	(11.01)	41.92
Combine Heat and Power (CHP)	$ 630	10.53%	$ 43.30	$ 23.06	$ 3.59	$ 26.65	$ 69.95	85%	9.39	393.11	36.24	$ 3.59	4.64	-	-	53.87
Customer Owned Standby Generation **	$ 135	15.34%	$ 19.93	-	-	-	$ 19.93	2%	98.90	633.45	66.51	$ 20.00	-	-	-	185.41
Compressed Air Energy Storage (CAES)	$ 679	9.29%	$ 63.08	$ 4.70	$ 1.35	$ 6.05	$ 69.13	25%	31.57	-	35.71	$ 1.20	-	3.91	-	72.38

Notes for the Supply Side Option Tables C.27 and C.28
***** Resources selected for a portfolio. Capacity Factor for these resources is based on average IRP results.
****** Customer-owned standby generation capital costs only include the costs to interconnect to PacifiCorp's system.

Costs are expressed as real levelized $/MWh costs in CY 2004 $.
Environmental Adders: Levelized $/Ton
SO_2: $715
NO_X: $1,347
Hg: $26,191 ($/lb)
CO_2: $5

PC: Pulverized Coal
CCCT: Combine Cycle Combustion Turbine
SCCT: Simple Cycle Combustion Turbine
IGCC: Integrated Gasification Combine Cycle
Brownfield: New facilities at a location with existing infrastructure and plant equipment.
Greenfield: Facilities constructed at a new site with minimal or no existing infrastructure and plant equipment.

Transmission

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.

APPENDIX D – PORTFOLIO CAPITAL COST SUMMARY TABLE

Table D.1 – Portfolio Capital Costs

Portfolio Capital Costs (MM FY$2004)		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Preferred Portfolio: Portfolio E with DSM											
East	UT Brownfield Coal	-	-	-	-	-	-	970	-	-	-
	WY Brownfield Coal	-	-	-	-	-	-	-	-	-	694
	UT Dry Cool CCCT w/ DF	-	-	-	-	308	-	-	-	-	-
	UT Wet Cool CCCT w/ DF	-	-	-	-	-	-	-	-	349	-
West	Dry Cool CCCT w/ DF	-	-	-	-	-	-	-	353	-	-
Generation	2,674	-	-	-	-	308	-	970	353	349	694
Transmission	462	-	-	-	-	143	-	65	5	60	189
Total	3,136	-	-	-	-	451	-	1,035	358	409	883
A: Reference											
East	UT Brownfield Coal	-	-	-	-	-	970	-	-	-	-
	WY Greenfield IGCC	-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF	-	-	-	308	-	-	-	-	-	-
	UT Wet Cool CCCT w/ DF	-	-	-	-	-	-	-	-	349	-
West	Dry Cool CCCT w/ DF	-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT	-	-	-	-	-	-	-	97	-	-
Generation	2,876	-	-	-	308	-	970	-	450	349	799
Transmission	531	-	-	-	143	-	65	-	10	60	252
Total	3,407	-	-	-	451	-	1,035	-	460	409	1,051
B: Remove FY2011 Utah PC, Replace w/ DC-CCCT											
East	WY Greenfield IGCC	-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF	-	-	-	308	-	308	-	-	-	-
	UT Wet Cool CCCT w/ DF	-	-	-	-	-	-	-	-	349	-
West	Dry Cool CCCT w/ DF	-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT	-	-	-	-	-	-	-	97	-	-
Generation	2,214	-	-	-	308	-	308	-	450	349	799
Transmission	531	-	-	-	143	-	65	-	10	60	252
Total	2,745	-	-	-	451	-	374	-	460	409	1,051
C: Replace FY2009 CCCT with Aeros											
East	UT Brownfield Coal	-	-	-	-	-	970	-	-	-	-
	WY Greenfield IGCC	-	-	-	-	-	-	-	-	-	799
	UT Wet Cool CCCT w/ DF	-	-	-	-	-	-	-	-	349	-
	UT IC Aero SCCT	-	-	-	292	-	-	-	-	-	-
West	Dry Cool CCCT w/ DF	-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT	-	-	-	-	-	-	-	97	-	-
Generation	2,860	-	-	-	292	-	970	-	450	349	799
Transmission	428	-	-	-	40	-	65	-	10	60	252
Total	3,288	-	-	-	332	-	1,035	-	460	409	1,051
D: Defer FY2011 Utah PC, Replace w/ WC-CCCT											
East	UT Brownfield Coal	-	-	-	-	-	-	-	-	970	-
	WY Greenfield IGCC	-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF	-	-	-	308	-	-	-	-	-	-
	UT Wet Cool CCCT w/ DF	-	-	-	-	-	349	-	-	-	-
West	Dry Cool CCCT w/ DF	-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT	-	-	-	-	-	-	-	97	-	-
Generation	2,876	-	-	-	308	-	349	-	450	970	799
Transmission	531	-	-	-	143	-	60	-	10	65	252
Total	3,407	-	-	-	451	-	409	-	460	1,035	1,051
E: Replace FY2015 IGCC with Wyoming PC Coal											
East	UT Brownfield Coal	-	-	-	-	-	970	-	-	-	-
	WY Brownfield Coal	-	-	-	-	-	-	-	-	-	694
	UT Dry Cool CCCT w/ DF	-	-	-	308	-	-	-	-	-	-
	UT Wet Cool CCCT w/ DF	-	-	-	-	-	-	-	-	349	-
West	Dry Cool CCCT w/ DF	-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT	-	-	-	-	-	-	-	97	-	-
Generation	2,772	-	-	-	308	-	970	-	450	349	694
Transmission	467	-	-	-	143	-	65	-	10	60	189
Total	3,239	-	-	-	451	-	1,035	-	460	409	883
F: Transmission Expansion											
East	WY Brownfield Coal	-	-	-	-	-	694	-	-	-	-
	WY Greenfield IGCC	-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF	-	-	-	308	-	-	-	-	-	-
	UT Wet Cool CCCT w/ DF	-	-	-	-	-	-	-	-	349	-
West	Dry Cool CCCT w/ DF	-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT	-	-	-	-	-	-	-	97	-	-
Generation	2,600	-	-	-	308	-	694	-	450	349	799
Transmission	728	-	-	-	143	-	263	-	10	60	252
Total	3,329	-	-	-	451	-	957	-	460	409	1,051

Note: DSM programs have no capital costs, thus they were omitted from Table D.1.

Portfolio Capital Costs (MM FY$2004)			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
G: Build on East Side vs. West Side												
East	UT Brownfield Coal		-	-	-	-	-	970	-	-	-	-
	WY Greenfield IGCC		-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	-	-	-
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	-	-	-	349	-
	UT IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
Generation		2,876	-	-	-	308	-	970	-	450	349	799
Transmission		566	-	-	-	143	-	65	-	45	60	252
Total		3,442	-	-	-	451	-	1,035	-	495	409	1,051
H: Replace FY2014 CCCT with Compressed Air Energy Storage												
East	UT Brownfield Coal		-	-	-	-	-	970	-	-	-	-
	WY Greenfield IGCC		-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	-	-	-
	Compressed Air Energy Storage		-	-	-	-	-	-	-	-	258	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		2,785	-	-	-	308	-	970	-	450	258	799
Transmission		663	-	-	-	143	-	65	-	10	192	252
Total		3,448	-	-	-	451	-	1,035	-	460	450	1,051
I: Replace FY2014 CCCT with Hydro Pumped Storage												
East	UT Brownfield Coal		-	-	-	-	-	970	-	-	-	-
	WY Greenfield IGCC		-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	-	-	-
	Pumped Storage		-	-	-	-	-	-	-	-	348	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		2,875	-	-	-	308	-	970	-	450	348	799
Transmission		663	-	-	-	143	-	65	-	10	192	252
Total		3,538	-	-	-	451	-	1,035	-	460	540	1,051
J: Portfolio B, with Wyoming PC Replacing IGCC												
East	WY Brownfield Coal		-	-	-	-	-	-	-	-	-	694
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	308	-	-	-	-
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	-	-	-	349	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		2,110	-	-	-	308	-	308	-	450	349	694
Transmission		467	-	-	-	143	-	65	-	10	60	189
Total		2,577	-	-	-	451	-	374	-	460	409	883
K: Portfolio C, with Wyoming PC Replacing IGCC												
East	UT Brownfield Coal		-	-	-	-	-	970	-	-	-	-
	WY Brownfield Coal		-	-	-	-	-	-	-	-	-	694
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	-	-	-	349	-
	UT IC Aero SCCT		-	-	-	292	-	-	-	-	-	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		2,756	-	-	-	292	-	970	-	450	349	694
Transmission		364	-	-	-	40	-	65	-	10	60	189
Total		3,120	-	-	-	332	-	1,035	-	460	409	883
L: Portfolio D, with Wyoming PC Replacing IGCC												
East	UT Brownfield Coal		-	-	-	-	-	-	-	-	970	-
	WY Brownfield Coal		-	-	-	-	-	-	-	-	-	694
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	-	-	-
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	349	-	-	-	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		2,772	-	-	-	308	-	349	-	450	970	694
Transmission		467	-	-	-	143	-	60	-	10	65	189
Total		3,239	-	-	-	451	-	409	-	460	1,035	883
M: All Gas with CCCTs												
East	UT Dry Cool CCCT w/ DF		-	-	-	308	-	308	-	-	-	-
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	-	-	-	349	349
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		1,764	-	-	-	308	-	308	-	450	349	349
Transmission		338	-	-	-	143	-	65	-	10	60	60
Total		2,103	-	-	-	451	-	374	-	460	409	409
N: All Gas with CCCTs and IC Aeros												
East	Dry Cool CCCT w/ DF		-	-	-	-	-	308	-	-	-	-
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	-	-	-	349	349
	UT IC Aero SCCT		-	-	-	292	-	-	-	-	-	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		1,748	-	-	-	292	-	308	-	450	349	349
Transmission		313	-	-	-	40	-	143	-	10	60	60
Total		2,061	-	-	-	332	-	451	-	460	409	409

Portfolio Capital Costs (MM FY$2004)			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
O: UT & WY IGCC												
East	UT Greenfield IGCC		-	-	-	-	-	-	-	-	799	-
	WY Greenfield IGCC		-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	-	-	-
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	349	-	-	-	-
	UT IC Aero SCCT		-	-	-	-	-	-	-	-	-	97
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		2,802	-	-	-	308	-	349	-	450	799	896
Transmission		531	-	-	-	143	-	60	-	10	65	252
Total		3,333	-	-	-	451	-	409	-	460	864	1,149
P: CEM-selected Portfolio												
East	UT Brownfield Coal		-	-	-	-	-	-	970	-	-	-
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	-	-	308
	UT IC Aero SCCT		-	-	-	-	-	-	-	-	146	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	49	-	-	49	49
Generation		2,231	-	-	-	308	-	49	970	353	195	357
Transmission		323	-	-	-	143	-	5	65	5	40	65
Total		2,554	-	-	-	451	-	54	1,035	358	235	422
Q: Transmission Expansion with Additional Wyoming Pulverized Coal												
East	UT Brownfield Coal		-	-	-	-	-	970	-	-	-	-
	WY Brownfield Coal (2 Units)		-	-	-	-	-	-	-	-	1,651	-
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	-	-	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		3,379	-	-	-	308	-	970	-	450	1,651	-
Transmission		846	-	-	-	143	-	139	-	10	554	-
Total		4,225	-	-	-	451	-	1,109	-	460	2,205	-
18% PM												
East	UT Brownfield Coal		-	-	-	-	-	970	-	-	-	-
	WY Greenfield IGCC		-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	-	-	-
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	-	-	-	349	-
	UT IC Aero SCCT		-	-	-	-	97	-	-	97	-	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	97	-	-
Generation		3,071	-	-	-	308	97	970	-	547	349	799
Transmission		571	-	-	-	143	40	65	-	10	60	252
Total		3,642	-	-	-	451	137	1,035	-	557	409	1,051
12% PM												
East	UT Brownfield Coal		-	-	-	-	-	970	-	-	-	-
	WY Greenfield IGCC		-	-	-	-	-	-	-	-	-	799
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	-	-	-	349	-
	UT IC Aero SCCT		-	-	-	-	49	-	49	49	-	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	-	-	49
Generation		2,665	-	-	-	-	49	970	49	401	349	848
Transmission		428	-	-	-	-	40	65	-	10	60	252
Total		3,093	-	-	-	-	89	1,035	49	411	409	1,100
Replace Front Office Transactions												
East	UT Brownfield Coal		-	-	-	-	-	970	-	-	-	-
	WY Greenfield IGCC		-	-	-	-	-	-	-	-	-	799
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	308	-	-
	UT Wet Cool CCCT w/ DF		-	-	-	349	-	-	-	-	-	-
West	Dry Cool CCCT w/ DF		-	-	-	353	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	-	-	49
Generation		3,488	-	-	-	1,010	-	970	-	661	-	848
Transmission		601	-	-	-	208	-	65	-	70	-	257
Total		4,090	-	-	-	1,218	-	1,035	-	731	-	1,105
Portfolio E with CHP												
East	UT Brownfield Coal		-	-	-	-	-	970	-	-	-	-
	WY Brownfield Coal		-	-	-	-	-	-	-	-	-	694
	UT Dry Cool CCCT w/ DF		-	-	-	308	-	-	-	-	-	-
	UT Wet Cool CCCT w/ DF		-	-	-	-	-	-	-	-	349	-
West	Dry Cool CCCT w/ DF		-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT		-	-	-	-	-	-	-	49	-	-
Generation		2,723	-	-	-	308	-	970	-	401	349	694
Transmission		467	-	-	-	143	-	65	-	10	60	189
Total		3,190	-	-	-	451	-	1,035	-	411	409	883

Portfolio Capital Costs (MM FY$2004)		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Portfolio E with Customer Standby Generation											
East	UT Brownfield Coal	-	-	-	-	-	-	970	-	-	-
	WY Brownfield Coal	-	-	-	-	-	-	-	-	-	694
	UT Dry Cool CCCT w/ DF	-	-	-	-	308	-	-	-	-	-
	UT Wet Cool CCCT w/ DF	-	-	-	-	-	-	-	-	349	-
	Standby Generation	-	-	-	10	-	-	-	-	-	-
West	Dry Cool CCCT w/ DF	-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT	-	-	-	-	-	-	-	49	-	-
	Standby Generation	-	-	-	-	-	-	-	5	-	-
Generation	2,738	-	-	-	10	308	-	970	407	349	694
Transmission	467	-	-	-	-	143	-	65	10	60	189
Total	3,205	-	-	-	10	451	-	1,035	417	409	883
Early IGCC Commercial Viability											
East	Greenfield IGCC 2	-	-	-	-	-	1,067	-	-	-	-
	Brownfield Coal	-	-	-	-	-	-	-	-	-	694
	Dry Cool CCCT w/ DF	-	-	-	308	-	-	-	-	-	-
	Wet Cool CCCT w/ DF	-	-	-	-	-	-	-	-	349	-
West	Dry Cool CCCT w/ DF	-	-	-	-	-	-	-	353	-	-
	IC Aero SCCT	-	-	-	-	-	-	-	97	-	-
Gen Total	2,869	-	-	-	308	-	1,067	-	450	349	694
Transm	467	-	-	-	143	-	65	-	10	60	189
Total	3,336	-	-	-	451	-	1,133	-	460	409	883

APPENDIX E – PORTFOLIO SCORECARD AND RESOURCE EMISSION COSTS

Table E.1 – Portfolio Scorecard

	PREFERRED PORTFOLIO	CANDIDATE PORTFOLIOS			
		A	B	C	D
VALUE MEASURE	E with DSM	Reference	Remove UT (PC), Rplc w/DC-CCCT	Rplc FY09 CCCT w/Aeros	Defer UT (PC), Rplc w/WC-CCCT
Comparative PVRR Ranking	1	10	13	9	11
Present Value Rev. Req't (20 Year $000)	**13,150,091**	**13,374,170**	**13,398,143**	**13,364,607**	**13,376,195**
Percent **Greater** Than Lowest PVRR	0.000%	1.704%	1.886%	1.631%	1.719%
Incremental Net Variable Power Cost	10,960,502	10,941,536	11,514,098	11,014,967	11,105,313
Incremental Real Levelized Fixed Cost	2,184,993	2,432,635	1,884,045	2,349,640	2,270,882
Gen. Capital Cost (2004$-millions)	2,674	2,876	2,214	2,860	2,876
Transmission Cost (2004$-millions)	462	531	531	428	531
Emissions (2006-2025 PVRR $000)	**(439,895)**	**(459,986)**	**(626,370)**	**(463,782)**	**(483,579)**
CO_2 (thousand tons 2010-2025)	840,603	837,170	804,595	834,932	831,938
CO_2 (% of cap)	99%	99%	95%	98%	98%
SO_2 (thousand tons 2006-2025)	965	960	902	962	960
SO_2 (% of cap)	65%	65%	61%	65%	65%
NO_x (thousand tons 2010-2025)	860	855	849	857	857
NO_x (% of cap)	78%	78%	77%	78%	78%
Hg (thousand tons 2010-2025)	0.0025	0.0025	0.0024	0.0025	0.0025
Hg (% of cap)	53%	52%	50%	52%	52%
Market Purchases					
2015 HLH					
PAC East (% of load)	0.0%	0.0%	0.0%	0.0%	0.0%
PAC East Average MW	0	0	0	0	0
PAC West (% of load)	1.6%	1.6%	1.7%	1.6%	1.6%
PAC West Average MW	27	27	28	26	27
2015 LLH					
PAC East (% of load)	0.0%	0.0%	0.0%	0.0%	0.0%
PAC East Average MW	0	0	0	0	0
PAC West (% of load)	1.1%	1.1%	1.2%	1.1%	1.0%
PAC West Average MW	10	10	11	10	10
Market Sales					
2015 HLH					
PAC East (% of owned Generation)	7.7%	7.7%	7.6%	7.6%	7.7%
PAC East Average MW	347	347	344	343	347
PAC West (% of owned Generation)	44.7%	44.7%	44.8%	45.9%	44.8%
PAC West Average MW	223	223	223	228	223
2015 LLH					
PAC East (% of owned Generation)	6.4%	6.4%	6.4%	6.4%	6.4%
PAC East Average MW	288	288	287	288	288
PAC West (% of owned Generation)	38.2%	38.2%	38.6%	38.9%	38.4%
PAC West Average MW	190	190	192	193	191
Unit Capacity Factors*					
2015					
Existing Coal East	88.5%	88.5%	92.0%	88.7%	88.5%
Existing CCGT East	55.1%	55.1%	71.1%	57.9%	55.1%
Existing Peaker East	1.0%	1.0%	1.1%	1.0%	1.0%
Existing Other East	99.0%	99.0%	99.0%	99.0%	99.0%
IRP Coal East	100.0%	100.0%	0.0%	100.0%	100.0%
IRP CCGT East	29.1%	29.1%	32.2%	39.8%	28.9%
IRP Peaker East	0.0%	0.0%	0.0%	8.9%	0.0%
IRP Other East	14.2%	14.2%	14.7%	14.3%	14.2%
Existing Coal West	95.1%	95.1%	95.6%	95.2%	95.3%
Existing CCGT West	79.8%	79.8%	81.7%	80.4%	80.1%
Existing Other West	99.9%	99.9%	100.0%	100.0%	99.9%
IRP CCGT West	47.0%	47.0%	48.6%	48.4%	47.0%
IRP Peaker West	9.4%	9.4%	9.8%	9.4%	9.3%
Transfers (MWa)					
2015					
East-West Transfer	10	10	6	10	10
West-East Transfer	149	149	172	155	151

* Capacity factors reflect a representative dispatch solution constrained by firm transmission rights. This is a conservative market modeling consumption.

VALUE MEASURE	CANDIDATE PORTFOLIOS CONT. E Rplc IGCC w/(PC) Coal	F Transmission Expansion	G Build on East vs West	H Rplc FY14 CCCT w/CAES	I Rplc FY14 CCCT w/Hydro PS
Comparative PVRR Ranking	5	14	12	15	17
Present Value Rev. Req't (20 Year $000)	**13,284,523**	**13,490,999**	**13,385,996**	**13,492,292**	**13,534,586**
Percent **Greater** Than Lowest PVRR	1.022%	2.592%	1.794%	2.602%	2.924%
Incremental Net Variable Power Cost	10,900,457	11,182,048	10,936,884	11,068,306	11,050,772
Incremental Real Levelized Fixed Cost	2,384,066	2,308,951	2,449,112	2,423,986	2,483,814
Gen. Capital Cost (2004$-millions)	2,772	2,600	2,876	2,785	2,875
Transmission Cost (2004$-millions)	467	728	566	663	663
Emissions (2006-2025 PVRR $000)	**(426,657)**	**(518,395)**	**(459,412)**	**(491,569)**	**(485,491)**
CO_2 (thousand tons 2010-2025)	844,254	826,066	837,271	828,072	829,111
CO_2 (% of cap)	100%	97%	99%	98%	98%
SO_2 (thousand tons 2006-2025)	964	912	960	961	962
SO_2 (% of cap)	65%	62%	65%	65%	65%
NO_x (thousand tons 2010-2025)	859	861	855	856	857
NO_x (% of cap)	78%	78%	78%	78%	78%
Hg (thousand tons 2010-2025)	0.0025	0.0025	0.0025	0.0025	0.0025
Hg (% of cap)	53%	52%	52%	52%	52%
Market Purchases					
2015 HLH					
PAC East (% of load)	0.0%	0.0%	0.0%	0.1%	0.1%
PAC East Average MW	0	0	0	3	5
PAC West (% of load)	1.6%	2.4%	1.7%	1.9%	1.9%
PAC West Average MW	27	40	29	32	32
2015 LLH					
PAC East (% of load)	0.0%	0.0%	0.0%	0.1%	0.1%
PAC East Average MW	0	0	0	1	1
PAC West (% of load)	1.1%	1.4%	1.0%	1.1%	1.2%
PAC West Average MW	11	14	10	11	11
Market Sales					
2015 HLH					
PAC East (% of owned Generation)	7.7%	7.4%	7.7%	7.3%	7.4%
PAC East Average MW	348	336	348	331	334
PAC West (% of owned Generation)	43.6%	37.3%	44.8%	38.7%	44.3%
PAC West Average MW	217	186	223	220	220
2015 LLH					
PAC East (% of owned Generation)	6.4%	6.4%	6.4%	6.3%	6.3%
PAC East Average MW	289	288	288	287	287
PAC West (% of owned Generation)	37.8%	35.3%	38.8%	33.5%	38.3%
PAC West Average MW	188	175	193	190	191
Unit Capacity Factors*					
2015					
Existing Coal East	88.0%	90.0%	88.5%	89.1%	89.4%
Existing CCGT East	53.7%	62.0%	55.2%	62.0%	61.3%
Existing Peaker East	0.9%	2.6%	0.8%	1.7%	1.6%
Existing Other East	99.0%	99.0%	99.0%	99.0%	99.0%
IRP Coal East	100.0%	0.0%	100.0%	100.0%	100.0%
IRP CCGT East	27.2%	31.5%	29.2%	27.7%	26.3%
IRP Peaker East	0.0%	0.0%	7.3%	0.0%	0.0%
IRP Other East	14.1%	15.2%	13.0%	17.4%	16.8%
Existing Coal West	95.1%	95.5%	94.9%	95.2%	95.3%
Existing CCGT West	77.9%	75.6%	80.6%	80.3%	80.7%
Existing Other West	99.9%	99.8%	100.0%	99.9%	99.9%
IRP CCGT West	45.2%	38.2%	47.8%	49.0%	48.8%
IRP Peaker West	8.2%	8.8%	0.0%	10.8%	10.8%
Transfers (MWa)					
2015					
East-West Transfer	8	-	10	9	9
West-East Transfer	205	490	139	188	186

* Capacity factors reflect a representative dispatch solution constrained by firm transmission rights. This is a conservative market modeling consumption.

	CANDIDATE PORTFOLIOS CONT.				
	J	**K**	**L**	**M**	**N**
VALUE MEASURE	**B, w/WY(PC) Rplc IGCC**	**C, w/WY(PC) Rplc IGCC**	**D, w/WY(PC) Rplc IGCC**	**All Gas CCCT**	**All Gas CCCT / Aeros**
Comparative PVRR Ranking	**8**	**4**	**6**	**2**	**7**
Present Value Rev. Req't (20 Year $000)	**13,303,487**	**13,269,244**	**13,286,028**	**13,255,607**	**13,292,238**
Percent **Greater** Than Lowest PVRR	1.167%	0.906%	1.034%	0.802%	1.081%
Incremental Net Variable Power Cost	11,468,012	10,968,173	11,063,715	11,680,040	11,755,152
Incremental Real Levelized Fixed Cost	1,835,476	2,301,071	2,222,313	1,575,567	1,537,085
Gen. Capital Cost (2004$-millions)	2,110	2,756	2,772	1,764	1,748
Transmission Cost (2004$-millions)	467	364	467	338	313
Emissions (2006-2025 PVRR $000)	**(590,904)**	**(426,435)**	**(450,133)**	**(667,809)**	**(674,392)**
CO_2 (thousand tons 2010-2025)	811,965	843,056	839,038	796,264	794,031
CO_2 (% of cap)	96%	99%	99%	94%	94%
SO_2 (thousand tons 2006-2025)	907	966	965	899	899
SO_2 (% of cap)	61%	65%	65%	61%	61%
NO_x (thousand tons 2010-2025)	854	861	861	844	845
NO_x (% of cap)	78%	78%	78%	77%	77%
Hg (thousand tons 2010-2025)	0.0024	0.0025	0.0025	0.0023	0.0023
Hg (% of cap)	50%	53%	52%	49%	49%
Market Purchases					
2015 HLH					
PAC East (% of load)	0.0%	0.0%	0.0%	0.0%	0.0%
PAC East Average MW	0	0	0	0	0
PAC West (% of load)	1.6%	1.5%	1.6%	1.7%	1.7%
PAC West Average MW	28	26	27	28	28
2015 LLH					
PAC East (% of load)	0.0%	0.0%	0.0%	0.0%	0.0%
PAC East Average MW	0	0	0	0	0
PAC West (% of load)	1.2%	1.1%	1.1%	1.3%	1.3%
PAC West Average MW	12	11	11	13	13
Market Sales					
2015 HLH					
PAC East (% of owned Generation)	7.6%	7.6%	7.7%	7.7%	7.7%
PAC East Average MW	344	346	348	350	349
PAC West (% of owned Generation)	43.9%	45.1%	43.7%	40.2%	46.3%
PAC West Average MW	219	224	217	228	230
2015 LLH					
PAC East (% of owned Generation)	6.4%	6.4%	6.4%	6.4%	6.4%
PAC East Average MW	288	289	289	288	288
PAC West (% of owned Generation)	38.2%	38.5%	37.9%	33.9%	39.0%
PAC West Average MW	190	191	189	193	194
Unit Capacity Factors*					
2015					
Existing Coal East	91.6%	88.1%	88.0%	91.7%	91.7%
Existing CCGT East	68.8%	56.4%	53.8%	66.3%	70.5%
Existing Peaker East	1.0%	0.8%	0.9%	1.0%	1.0%
Existing Other East	99.0%	99.0%	99.0%	99.0%	99.0%
IRP Coal East	0.0%	100.0%	100.0%	0.0%	0.0%
IRP CCGT East	30.9%	37.6%	26.9%	37.3%	43.8%
IRP Peaker East	0.0%	8.3%	0.0%	0.0%	7.6%
IRP Other East	14.5%	13.3%	14.1%	11.5%	11.7%
Existing Coal West	95.7%	95.2%	95.3%	95.8%	95.8%
Existing CCGT West	80.2%	78.5%	78.3%	87.9%	88.4%
Existing Other West	100.0%	100.0%	99.9%	100.0%	100.0%
IRP CCGT West	46.9%	46.9%	45.2%	55.2%	56.0%
IRP Peaker West	8.6%	8.2%	8.2%	10.4%	10.7%
Transfers (MWa)					
2015					
East-West Transfer	5	8	8	65	64
West-East Transfer	228	207	208	29	30

* Capacity factors reflect a representative dispatch solution constrained by firm transmission rights. This is a conservative market modeling consumption.

	CANDIDATE PORTFOLIOS CONT.		
	O	P	Q
VALUE MEASURE	UT / WY IGCC	CEM	Trans Expansion w/Add WY PC
Comparative PVRR Ranking	16	3	18
Present Value Rev. Req't (20 Year $000)	**13,515,303**	**13,257,388**	**13,584,520**
Percent **Greater** Than Lowest PVRR	2.777%	0.816%	3.304%
Incremental Net Variable Power Cost	11,321,381	11,290,423	10,572,867
Incremental Real Levelized Fixed Cost	2,193,923	1,966,965	3,011,653
Gen. Capital Cost (2004$-millions)	2,802	2,231	3,379
Transmission Cost (2004$-millions)	531	323	846
Emissions (2006-2025 PVRR $000)	**(563,246)**	**(518,748)**	**(321,873)**
CO_2 (thousand tons 2010-2025)	814,468	822,220	869,896
CO_2 (% of cap)	96%	97%	103%
SO_2 (thousand tons 2006-2025)	950	960	966
SO_2 (% of cap)	64%	65%	65%
NO_x (thousand tons 2010-2025)	850	854	865
NO_x (% of cap)	77%	78%	79%
Hg (thousand tons 2010-2025)	0.0024	0.0024	0.0030
Hg (% of cap)	51%	51%	63%
Market Purchases			
2015 HLH			
PAC East (% of load)	0.0%	0.0%	0.0%
PAC East Average MW	0	0	0
PAC West (% of load)	1.6%	1.8%	3.1%
PAC West Average MW	28	30	51
2015 LLH			
PAC East (% of load)	0.0%	0.0%	0.0%
PAC East Average MW	0	0	0
PAC West (% of load)	1.1%	1.3%	1.8%
PAC West Average MW	11	12	18
Market Sales			
2015 HLH			
PAC East (% of owned Generation)	7.6%	7.7%	7.5%
PAC East Average MW	344	346	339
PAC West (% of owned Generation)	45.3%	44.7%	29.8%
PAC West Average MW	225	223	148
2015 LLH			
PAC East (% of owned Generation)	6.4%	6.4%	6.4%
PAC East Average MW	288	288	288
PAC West (% of owned Generation)	39.1%	37.6%	31.0%
PAC West Average MW	194	187	154
Unit Capacity Factors*			
2015			
Existing Coal East	90.3%	89.3%	86.2%
Existing CCGT East	64.1%	68.3%	50.6%
Existing Peaker East	1.2%	1.2%	2.3%
Existing Other East	99.0%	99.0%	99.1%
IRP Coal East	100.0%	100.0%	96.8%
IRP CCGT East	33.5%	26.8%	22.3%
IRP Peaker East	10.0%	8.9%	7.7%
IRP Other East	15.4%	15.1%	10.2%
Existing Coal West	95.5%	96.0%	86.2%
Existing CCGT West	81.8%	84.7%	50.6%
Existing Other West	100.0%	100.0%	99.1%
IRP CCGT West	48.0%	54.9%	22.3%
IRP Peaker West	9.6%	9.7%	7.7%
Transfers (MWa)			
2015			
East-West Transfer	8	67	-
West-East Transfer	164	39	669

* Capacity factors reflect a representative dispatch solution constrained by firm transmission rights. This is a conservative market modeling consumption.

	STRESS PORTFOLIOS					
	--	--	--	--	--	--
VALUE MEASURE	**12% PM**	**18% PM**	**Repl FO Transactions**	**Portfolio E with CHP**	**Portfolio E with Standby Gen**	**Early IGCC Commercial Viab.**
Comparative PVRR Ranking	--	--	--	--	--	--
Present Value Rev. Req't (20 Year $000)	**13,144,057**	**13,560,950**	**13,923,692**	**13,247,499**	**13,224,908**	**13,506,609**
Percent **Greater** Than Lowest PVRR	--	--	--	--	--	--
Incremental Net Variable Power Cost	11,049,966	10,919,252	10,741,853	10,843,401	10,970,413	11,020,833
Incremental Real Levelized Fixed Cost	2,094,091	2,641,698	3,181,839	2,404,097	2,254,494	2,485,776
Gen. Capital Cost (2004$-millions)	2,665	3,071	3,488	2,723	2,738	2,869
Transmission Cost (2004$-millions)	428	571	601	467	467	467
Emissions (2006-2025 PVRR $000)	**(482,445)**	**(444,067)**	**(369,911)**	**(412,482)**	**(438,885)**	**(496,919)**
CO_2 (thousand tons 2010-2025)	830,154	841,218	860,694	846,703	840,909	832,218
CO_2 (% of cap)	98%	99%	101%	100%	99%	98%
SO_2 (thousand tons 2006-2025)	962	960	959	964	965	949
SO_2 (% of cap)	65%	65%	65%	65%	65%	64%
NO_x (thousand tons 2010-2025)	857	855	856	863	860	846
NO_x (% of cap)	78%	78%	78%	79%	78%	77%
Hg (thousand tons 2010-2025)	0.0025	0.0025	0.0025	0.0025	0.0025	0.0024
Hg (% of cap)	52%	53%	53%	53%	53%	50%
Market Purchases						
2015 HLH						
PAC East (% of load)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PAC East Average MW	0	0	0	0	0	0
PAC West (% of load)	1.8%	1.5%	1.0%	1.6%	1.6%	1.7%
PAC West Average MW	30	25	16	27	27	28
2015 LLH						
PAC East (% of load)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PAC East Average MW	1	0	0	0	0	0
PAC West (% of load)	1.0%	1.0%	0.8%	1.1%	1.1%	1.2%
PAC West Average MW	10	10	8	10	10	11
Market Sales						
2015 HLH						
PAC East (% of owned Generation)	7.5%	7.8%	7.6%	7.7%	7.7%	7.6%
PAC East Average MW	338	351	347	347	347	346
PAC West (% of owned Generation)	45.1%	45.8%	48.9%	44.7%	44.7%	43.5%
PAC West Average MW	224	228	243	223	223	216
2015 LLH						
PAC East (% of owned Generation)	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%
PAC East Average MW	288	288	289	288	288	288
PAC West (% of owned Generation)	39.1%	38.7%	40.7%	38.2%	38.2%	37.9%
PAC West Average MW	194	192	202	190	190	189
Unit Capacity Factors*						
2015						
Existing Coal East	88.7%	88.5%	88.5%	88.5%	88.5%	90.5%
Existing CCGT East	58.0%	55.1%	53.9%	55.1%	55.1%	63.5%
Existing Peaker East	1.6%	0.5%	0.5%	1.0%	1.0%	1.1%
Existing Other East	99.0%	99.0%	99.0%	99.0%	99.0%	99.4%
IRP Coal East	100.0%	100.0%	100.0%	100.0%	100.0%	99.6%
IRP CCGT East	39.9%	29.0%	22.8%	29.1%	29.1%	35.0%
IRP Peaker East	9.6%	6.9%	5.0%	0.0%	0.0%	8.8%
IRP Other East	17.6%	10.5%	0.0%	14.2%	14.2%	10.2%
Existing Coal West	95.1%	95.1%	94.7%	95.1%	95.1%	90.5%
Existing CCGT West	80.8%	80.2%	80.7%	79.8%	79.8%	63.5%
Existing Other West	100.0%	100.0%	100.0%	99.9%	99.9%	99.4%
IRP CCGT West	48.7%	47.6%	31.1%	47.0%	47.0%	35.0%
IRP Peaker West	10.2%	8.6%	4.9%	9.4%	9.4%	8.8%
Transfers (MWa)						
2015						
East-West Transfer	10	10	9	10	10	8
West-East Transfer	160	139	129	149	149	213

* Capacity factors reflect a representative dispatch solution constrained by firm transmission rights. This is a conservative market modeling consumption.

RESOURCE EMISSION COSTS

Table E.2 shows FY 2015 emission costs in cents-per-MWh for IRP proxy resources. The cost values and associated GWh generation are listed for a set of portfolios representing the resource technologies evaluated. See Appendix C, “Emission Costs”, for the relevant FY 2015 emission prices.

Table E.2 – Unit Emission Costs for FY 2015

	Generation	SO_2 Cost	NO_x Cost	Hg Cost	CO_2 Cost
Portfolio & Resources	**(GWh)**	**Cents/MWh**			
Preferred Portfolio (E with DSM)					
WY Brownfield Coal	24,213	26.4	77.2	25.0	875.9
UT Brownfield Coal	36,652	40.4	78.4	25.4	890.1
UT Dry Cool CCCT w/ DF	5,277	0.5	9.7	8.7	413.9
UT Wet Cool CCCT w/ DF	13,838	0.5	9.1	8.2	388.8
WMAIN Dry Cool CCCT w/ DF	17,358	0.5	9.5	8.6	405.8
East DSM, Irrigation Control	129	0.0	0.0	0.0	0.0
West DSM, Irrigation Control	129	0.0	0.0	0.0	0.0
East DSM, Comm. Light Control	57	0.0	0.0	0.0	0.0
Portfolio H					
WY IGCC (368 MW)	2,417	11.9	47.5	22.2	775.6
UT Brownfield Coal	4,581	40.4	78.4	25.4	890.1
UT Dry Cool CCCT w/ DF	1,176	0.5	9.7	8.7	414.2
WMAIN IC Aero SCCT	165	0.6	11.1	10.0	474.3
WMAIN Dry Cool CCCT w/ DF	2,324	0.5	9.5	8.5	405.4
East Compressed Air Energy Storage	62	0.3	0.0	5.0	236.3
Portfolio I					
IRP East IGCC (368 MW)	2,417	11.9	47.5	22.2	775.6
UT Brownfield Coal	4,581	40.4	78.4	25.4	890.1
UT Dry Cool CCCT w/ DF	1,117	0.5	9.7	8.7	414.3
WMAIN IC Aero SCCT	165	0.6	11.1	10.0	474.3
WMAIN Dry Cool CCCT w/ DF	2,314	0.5	9.5	8.5	405.3
East Hydro Pumped Storage	290	0.0	0.0	0.0	0.0
Portfolio Q					
UT Brownfield Coal	36,652	40.4	78.4	25.4	890.1
WY Brownfield Coal 1	36,652	40.4	78.4	63.6	911.8
WY Brownfield Coal 2 (383 MW)	24,388	41.9	81.3	65.9	944.9
UT IC Aero SCCT	3,692	0.6	10.4	9.4	446.7
WMAIN IC Aero SCCT	939	0.6	11.1	10.0	474.3
WMAIN Dry Cool CCCT w/ DF	13,877	0.5	9.5	8.5	405.0
Early IGCC Comm. Viability					
East IGCC (460 MW)	29,013	16.8	20.2	9.4	823.3
WY Brownfield Coal	24,241	26.4	77.2	25.0	875.9
UT Dry Cool CCCT w/ DF	5,858	0.5	9.7	8.7	413.5
UT Wet Cool CCCT w/ DF	14,711	0.5	9.1	8.2	388.9
WMAIN IC Aero SCCT	1,070	0.6	11.1	10.0	474.3
WMAIN Dry Cool CCCT w/ DF	17,208	0.5	9.5	8.5	405.3

APPENDIX F – PORTFOLIO LOAD AND RESOURCE BALANCES

LOAD AND RESOURCE CAPACITY REPORT

Table F.1 – Load and Resource Capacity Report (MW)

Fiscal Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
East										
Thermal	5,390	5,713	6,252	6,062	6,062	6,062	6,062	6,062	6,062	6,062
Hydro	100	100	100	100	100	100	100	100	100	100
DSM	108	131	131	131	131	131	131	131	131	0
Wind	9	9	9	9	9	9	9	9	9	9
Purchase	611	195	181	2	(3)	(2)	(1)	1	2	(1)
Interruptible	127	127	60	60	60	60	60	60	60	60
Transfers	454	454	454	454	454	454	454	454	454	454
East Existing Resources	6,799	6,729	7,187	6,818	6,813	6,814	6,816	6,817	6,818	6,684
RFP Wind	0	40	60	100	120	160	160	160	160	160
Front Office Transactions	100	400	450	700	700	700	700	700	700	700
QF	100	100	100	100	100	100	100	100	100	100
East Planned Resources	200	540	610	900	920	960	960	960	960	960
East Resources	6,999	7,269	7,797	7,718	7,733	7,774	7,776	7,777	7,778	7,644
Load	5,829	6,121	6,331	6,602	6,895	7,107	7,368	7,567	7,837	8,091
Sale	360	360	349	314	210	173	134	98	98	104
East Obligation	6,189	6,481	6,680	6,916	7,105	7,280	7,502	7,665	7,935	8,195
East Obligation x PM*	7,117	7,453	7,682	7,953	8,171	8,372	8,627	8,815	9,125	9,424
East Position	(119)	(184)	115	(236)	(438)	(598)	(852)	(1,038)	(1,347)	(1,780)
West										
Thermal	2,285	2,285	2,285	2,045	2,045	2,045	2,045	2,045	2,045	2,045
Hydro	630	691	684	681	681	677	677	677	677	677
Purchase	1,804	1,753	1,461	1,136	1,061	1,044	893	232	229	125
Transfers	(454)	(454)	(454)	(454)	(454)	(454)	(454)	(454)	(454)	(454)
West Existing Resources	4,265	4,275	3,976	3,408	3,333	3,312	3,161	2,500	2,497	2,393
RFP Wind	20	20	40	40	60	60	100	120	120	120
Front Office Transactions	200	150	200	400	400	400	500	500	500	500
West Planned Resources	220	170	240	440	460	460	600	620	620	620
West Resources	4,485	4,445	4,216	3,848	3,793	3,772	3,761	3,120	3,117	3,013
Load	3,583	3,529	3,649	3,110	3,162	3,214	3,253	3,295	3,360	3,448
Sale	215	165	95	95	95	95	95	40	40	39
West Obligation	3,798	3,694	3,744	3,205	3,257	3,309	3,348	3,335	3,400	3,487
West Obligation x PM*	4,368	4,248	4,306	3,686	3,746	3,805	3,850	3,835	3,910	4,010
West Position	117	197	(90)	162	47	(33)	(89)	(715)	(793)	(997)
System										
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
Total Resources	11,484	11,714	12,013	11,566	11,526	11,546	11,537	10,897	10,895	10,657
Obligation	9,987	10,175	10,424	10,121	10,362	10,589	10,850	11,000	11,335	11,682
Obligation x PM*	11,485	11,701	11,988	11,639	11,916	12,177	12,478	12,650	13,035	13,434
System Position	(1)	13	25	(73)	(390)	(631)	(941)	(1,753)	(2,140)	(2,777)

* - Planning Margin (PM) is 15%

PORTFOLIO RESOURCE ADDITION SUMMARY

Table F.2 – Portfolio Resource Addition Summary

Fiscal Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Portfolio:	**Preferred Portfolio (Portfolio E with DSM)**									
Resource Additions (MW)	-	-	-	88	613	613	1,188	1,774	2,423	2,806
Net Reserves (MW)	1,497	1,539	1,589	1,533	1,777	1,570	1,875	1,671	1,983	1,781
Net Reserves % Of Obligation	15%	15%	15%	15%	17%	15%	17%	15%	17%	15%
Portfolio:	**A:Reference Portfolio**									
Resource Additions (MW)	-	-	-	525	525	1,100	1,100	1,880	2,440	2,808
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,057	1,787	1,777	2,000	1,783
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	18%	15%
Portfolio:	**B: Remove FY2011 Utah PC, Replace w/ DC-CCCT**									
Resource Additions (MW)	-	-	-	525	525	1,050	1,050	1,830	2,390	2,758
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,007	1,737	1,727	1,950	1,733
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	17%	15%
Portfolio:	**C: Replace FY2009 CCCT with Aeros**									
Resource Additions (MW)	-	-	-	522	522	1,097	1,097	1,877	2,437	2,805
Net Reserves (MW)	1,497	1,539	1,589	1,967	1,686	2,054	1,784	1,774	1,997	1,780
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	18%	15%
Portfolio:	**D: Defer FY 2011 Utah PC, Replace w/ WC-CCCT**									
Resource Additions (MW)	-	-	-	525	525	1,085	1,085	1,865	2,440	2,808
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,042	1,772	1,762	2,000	1,783
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	18%	15%
Portfolio:	**E: Replace FY2015 IGCC w/PC Coal**									
Resource Additions (MW)	-	-	-	525	525	1,100	1,100	1,880	2,440	2,823
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,057	1,787	1,777	2,000	1,798
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	18%	15%
Portfolio:	**F: Transmission Expansion**									
Resource Additions (MW)	-	-	-	525	525	908	908	1,688	2,248	2,616
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	1,865	1,595	1,585	1,808	1,591
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	18%	15%	14%	16%	14%
Portfolio:	**G: Build on East Side vs. West Side**									
Resource Additions (MW)	-	-	-	525	525	1,100	1,100	1,860	2,420	2,788
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,057	1,787	1,757	1,980	1,763
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	17%	15%
Portfolio:	**H: Replace FY2014 CCCT with Compressed Air Energy Storage**									
Resource Additions (MW)	-	-	-	525	525	1,100	1,100	1,880	2,203	2,571
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,057	1,787	1,777	1,763	1,546
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	16%	13%
Portfolio:	**I: Replace FY2014 CCCT with Hydro Pumped Storage**									
Resource Additions (MW)	-	-	-	525	525	1,100	1,100	1,880	2,280	2,648
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,057	1,787	1,777	1,840	1,623
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	16%	14%

Table F.2 – Portfolio Resource Addition Summary (continued)

Fiscal Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Portfolio:	**J: Portfolio B, with Wyoming PC Replacing IGCC**									
Resource Additions (MW)	-	-	-	525	525	1,050	1,050	1,830	2,390	2,773
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,007	1,737	1,727	1,950	1,748
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	17%	15%
Portfolio:	**K: Portfolio C, with Wyoming PC Replacing IGCC**									
Resource Additions (MW)	-	-	-	522	522	1,097	1,097	1,877	2,437	2,820
Net Reserves (MW)	1,497	1,539	1,589	1,967	1,686	2,054	1,784	1,774	1,997	1,795
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	18%	15%
Portfolio:	**L: Portfolio D, with Wyoming PC Replacing IGCC**									
Resource Additions (MW)	-	-	-	525	525	1,085	1,085	1,865	2,440	2,823
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,042	1,772	1,762	2,000	1,798
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	18%	15%
Portfolio:	**M: All Gas with CCCTs**									
Resource Additions (MW)	-	-	-	525	525	1,050	1,050	1,830	2,390	2,950
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,007	1,737	1,727	1,950	1,925
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	17%	16%
Portfolio:	**N: All Gas with CCCTs and IC Aeros**									
Resource Additions (MW)	-	-	-	522	522	1,047	1,047	1,827	2,387	2,947
Net Reserves (MW)	1,497	1,539	1,589	1,967	1,686	2,004	1,734	1,724	1,947	1,922
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	17%	16%
Portfolio:	**O: UT & WY IGCC**									
Resource Additions (MW)	-	-	-	525	525	1,085	1,085	1,865	2,233	2,775
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,042	1,772	1,762	1,793	1,750
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	16%	15%
Portfolio:	**P: CEM-selected Portfolio**									
Resource Additions (MW)	-	-	-	525	525	622	1,197	1,783	2,141	2,763
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	1,579	1,884	1,680	1,701	1,738
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	15%	17%	15%	15%	15%
Portfolio:	**Q: Transmission Expansion with Additional Pulverized Coal**									
Resource Additions (MW)	-	-	-	525	525	1,100	1,100	1,880	2,838	2,838
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,057	1,787	1,777	2,398	1,813
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	21%	16%
Portfolio:	**12% Planning Margin**									
Resource Additions (MW)	-	-	-	-	87	662	749	1,422	1,982	2,447
Net Reserves (MW)	1,497	1,539	1,589	1,445	1,251	1,619	1,436	1,319	1,542	1,422
Net Reserves % Of Obligation	15%	15%	15%	14%	12%	15%	13%	12%	14%	12%
Portfolio:	**18% Planning Margin**									
Resource Additions (MW)	-	-	-	525	699	1,274	1,274	2,228	2,788	3,156
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,863	2,231	1,961	2,125	2,348	2,131
Net Reserves % Of Obligation	15%	15%	15%	19%	18%	21%	18%	19%	21%	18%

Table F.2 – Portfolio Resource Addition Summary (continued)

Fiscal Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Portfolio:	**No Front Office Transactions**									
Resource Additions (MW)	-	-	-	1,671	1,845	2,420	2,420	3,006	3,531	4,083
Net Reserves (MW)	1,097	889	839	1,916	1,809	2,177	1,807	1,603	1,791	1,758
Net Reserves % Of Obligation	11%	9%	8%	19%	17%	21%	17%	15%	16%	15%
Portfolio:	**Portfolio E with CHP**									
Resource Additions (MW)	-	-	-	525	525	1,100	1,100	1,873	2,433	2,816
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	2,057	1,787	1,770	1,993	1,791
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	19%	16%	16%	18%	15%
Portfolio:	**Portfolio E with Customer Standby Generation**									
Resource Additions (MW)	-	-	-	75	600	600	1,175	1,898	2,458	2,841
Net Reserves (MW)	1,497	1,539	1,589	1,520	1,764	1,557	1,862	1,795	2,018	1,816
Net Reserves % Of Obligation	15%	15%	15%	15%	17%	15%	17%	16%	18%	16%
Portfolio:	**Early IGCC Commercial Viability**									
Resource Additions (MW)	-	-	-	525	525	985	985	1,765	2,325	2,708
Net Reserves (MW)	1,497	1,539	1,589	1,970	1,689	1,942	1,672	1,662	1,885	1,683
Net Reserves % Of Obligation	15%	15%	15%	19%	16%	18%	15%	15%	17%	14%

APPENDIX G – RISK ASSESSMENT MODELING METHODOLOGY

INTRODUCTION

This appendix describes PacifiCorp's approach for assessing risk and uncertainty in its IRP analysis. This section focuses on the development of volatility and correlation parameters for important electricity market drivers used in the Stochastic risk analysis. The section also discusses the methodology and inputs for the Scenario risk analysis. Two risk scenarios were considered for this IRP. One scenario was varying the CO_2 emission allowance charges and the other scenario considered higher electricity and natural gas prices.

KEY UNCERTAINTIES

Performing analysis of the cost of electricity supply under an assumption of expected conditions in the future provides important information for decision makers regarding how each portfolio performs. However, decision makers are also interested in performance of these portfolios under influences that vary from expected. Of particular note for PacifiCorp are the following uncertainties:

Load

Retail load (or firm load obligations) can vary significantly in the short term due primarily to temperature fluctuations in the PacifiCorp service territory. An examination of historical daily load provides insight into how these loads might vary from day to day in the future. Over the longer term, economic conditions and technological changes have a significant effect on load growth rates.

Natural Gas Price

Natural gas prices have exhibited significant volatility in recent years. Not only does natural gas have multiple uses in heating, power generation, and industrial processing, but it also has enormous growth potential in other countries. An examination of historical daily natural gas prices provides insight into how these natural gas prices might vary from day to day in the future. Longer-term uncertainties relate to the supply and demand for natural gas as an energy resource.

Spot Market Electricity Prices

Spot market electricity prices, inherently linked to gas prices, affect portfolios through the dispatch of PacifiCorp generation assets. When spot prices are low, it may be economical to displace some of PacifiCorp's generation. When spot prices are high, it may become economical to operate coal and natural gas resources at levels higher than needed to cover firm obligations, contributing revenues that reduce system electricity costs. An examination of historical daily spot market electricity prices provides insight into how these prices might vary from day to day in the future. Longer-term market price trends are uncertain due to general economic conditions and general supply and demand for generating resources. These longer-term trends can have a significant effect on the value of competing portfolios.

Hydroelectric Generation

Hydroelectric ("hydro") generation makes up a significant portion of PacifiCorp's existing resource base. History demonstrates that the amount of generation will vary from time to time as a result of different precipitation levels. An examination of historical hydro generation data (both daily changes demonstrated by actual operation and longer-term changes reflected in hydro generation regulation models) provides insight into how it may vary in the future.

Generation Forced Outage

It is well understood that generation units are taken out of service from time to time as a result of unanticipated problems (forced outage), and the random nature of this aspect of generation must be accounted for in any portfolio analysis.

The analysis of uncertainty in outcomes from forced outages is achieved through Monte Carlo selection of the timing of the outage on an individual plant basis. This selection is made within the stochastic analysis mechanism of MARKETSYM.

STOCHASTIC ANALYSIS MODEL AND ASSUMPTIONS

PacifiCorp's analysis of potential portfolios attempts to look at the possible future performance of each portfolio under uncertainty. PacifiCorp is performing its assessment of portfolios with Henwood's MARKETSYM products on both a deterministic and stochastic basis. Deterministic forecasts are based on the expected value of all input parameters, whereas stochastic assessments include specific volatility and correlations among parameters. For the five uncertainties described previously there are potentially short-term and long-term volatilities as well as short-term and long-term correlations. The following is a discussion of these short-term and long-term parameters.

Short-Term Stochastic Model

PacifiCorp's analysis is being performed with the following stochastic variables:

- Fuel prices (natural gas price in the Northwest and natural gas price in Utah)
- Electricity market clearing prices (Mid-Columbia (MidC), California – Oregon Border (COB), Four Corners, and Palo Verde (PV))
- Electric transmission area loads (California, Oregon, Washington, Wyoming, Idaho, and Utah regions) and
- Hydro generation basins (PacifiCorp West and PacifiCorp East).

Henwood's stochastic analysis uses the modeling capability of the MARKETSYM stochastic module. In this process an expected value trajectory for each price or physical variable and a set of stochastic model parameters are developed and entered by the user, using stochastic data input tools. During execution, Monte Carlo simulation is performed with daily random draws for average daily values for prices and loads and weekly random draws for hydro generation energy availability. Within each week, generation units are committed and dispatched as if they have perfect foresight of stochastic values for that week only.

Two-Factor Mean-Reversion Model

The stochastic model used in PacifiCorp's analysis is a two-factor, lognormal or normal mean-reversion model. One factor represents short-run variations that are mean reverting, and the other factor represents longer-term variations that follow a random walk. Mean reversion implies that after a price is initially disrupted (higher or lower) it will tend to revert back towards its expected value. The rate at which the random variable tends to revert to the expected value is an input to the process. Separate volatility and correlation parameters are used for modeling short-run variations (e.g., uncertain weather or outages) and longer term variations (e.g., uncertain fuel supply costs, load growth, or hydro generation year). Antithetic sampling is used to reduce sampling variance.

The stochastic two-factor lognormal mean reversion model:

1. Simulates a general stochastic process capable of representing fuel prices, electricity prices, and hydro generation energy availability. The electric loads are assumed to follow a two-factor normal mean reversion model.
2. Uses an expected forecast as an equilibrium value for each time period.
3. Uses two distinct stochastic factors for each stochastic variable – for short-term and long-term variations.
4. Assumes a lognormal distribution for each stochastic factor except for electric loads which assumes a normal distribution.
5. Allows contemporaneous correlation among all, some, or none of the input and output variables.
6. Allows use of seasonal and annual volatility and correlation parameters, with short-term reversion to mean, to handle cyclical patterns of energy commodities.

The specific discrete time representation of the model is:

$$S_{n,t} = S_{n,t-1} + L_{n,t} - L_{n,t-1} + \alpha_{n,t}(L_{n,t-1} - S_{n,t-1}) + \sigma^S_{n,t}\varepsilon^S_{n,t} - \mathrm{Var}[S_{n,t}]/2 \qquad (1)$$

$$L_{n,t} = L_{n,t-1} + \delta_{n,t} - (\sigma^L_{n,t})^2/2 + \sigma^L_{n,t}\varepsilon^L_{n,t} \qquad (2)$$

$$\mathrm{E}\,[\varepsilon^S_{n,t} \cdot \varepsilon^L_{n,t}] = \mathrm{Cov}^{S,L}_{n,t} = 0 \Rightarrow \rho^{S,L}_{n,t} = 0 \qquad (3)$$ [13]

$$\mathrm{E}\,[\varepsilon^S_{m,t} \cdot \varepsilon^S_{n,t}] = \mathrm{Cov}^S_{m,n,t} \neq 0 \Rightarrow \rho^S_{m,n,t} \neq 0 \qquad (4)$$

$$\mathrm{E}\,[\varepsilon^L_{m,t} \cdot \varepsilon^L_{n,t}] = \mathrm{Cov}^L_{m,n,t} \neq 0 \Rightarrow \rho^L_{m,n,t} \neq 0 \qquad (5)$$

---

[13] Assuming zero correlation between the long and short-run stochastic changes is a simplifying assumption. However, this assumption represents movements in the stochastic variable that we would expect to observe in a real market situation. It is justified both by the unavailability of quantitative data from which to estimate a correlation, either positive or negative, between short-run shocks and long-run shocks and by the structure of the model in which short run shocks to the stochastic variable apply to deviations from the value of the long run distribution.

This assumption assures that positive (upward) short-run spikes in the value of the stochastic variable are statistically independent from positive (upward) trends in the long-run equilibrium value of the stochastic variable, and vice versa. Relaxing this assumption could lead to model (parameter) induced bias in the resulting value of the stochastic variable.

Where:

n = commodity (fuel price, electricity price, electric load or hydro generation)
t = time period of observation (e.g., day for prices and loads, or week for hydro generation)
S_n = logarithm of short-run or spot price for commodity *n*
L_n = logarithm of long-run or equilibrium price for commodity *n*
$\alpha_{n,t}$ = rate of mean-reversion in spot price for commodity n in period *t*
$\delta_{n,t}$ = expected rate of growth (drift) of equilibrium price for commodity n in period *t*
$\sigma^S_{n,t}$ = volatility of spot price returns for commodity n in period *t*
σ^L_n = volatility of equilibrium price growth rate for commodity *n*
ε^S = normally distributed random vector (mean = 0, s.d.= 1)
ε^L = normally distributed random vector (mean = 0, s.d.= 1)
$\rho^{S,L}$ = correlation of spot and long run price stochastic changes
$\rho^S_{m,n}$ = correlation of spot price stochastic changes for commodities *m* and *n*
$\rho^L_{m,n}$ = correlation of drift rate stochastic changes for commodities *m* and *n*
Var = variance.
$\mathrm{Cov}_{m,n}$ = variance-covariance matrix for stochastic changes in commodities *m* and *n*

For electricity prices daily values are used in the above model. Once the simulated average price is determined for each day, hourly spot prices for that day are scaled up or down in proportion to those for the expected daily price shape.

The error vectors are independent and identically distributed therefore, there is no autocorrelation within an error vector. This is the structure of the model used, and the parameters and coefficients are developed accordingly. Random shocks in successive periods are drawn independently, and short-term reversion to the mean is assumed. The primary justification for this assumption is the need to limit the complexity of the model. If this assumption were relaxed, a new stochastic process model would be implemented. Developing and utilizing data for autocorrelation of stochastic variables would add to the complexity of the analysis and simulation process. The feasibility of such a modification to the analytic process, or what the effect, if any, would be on the results has not been studied.

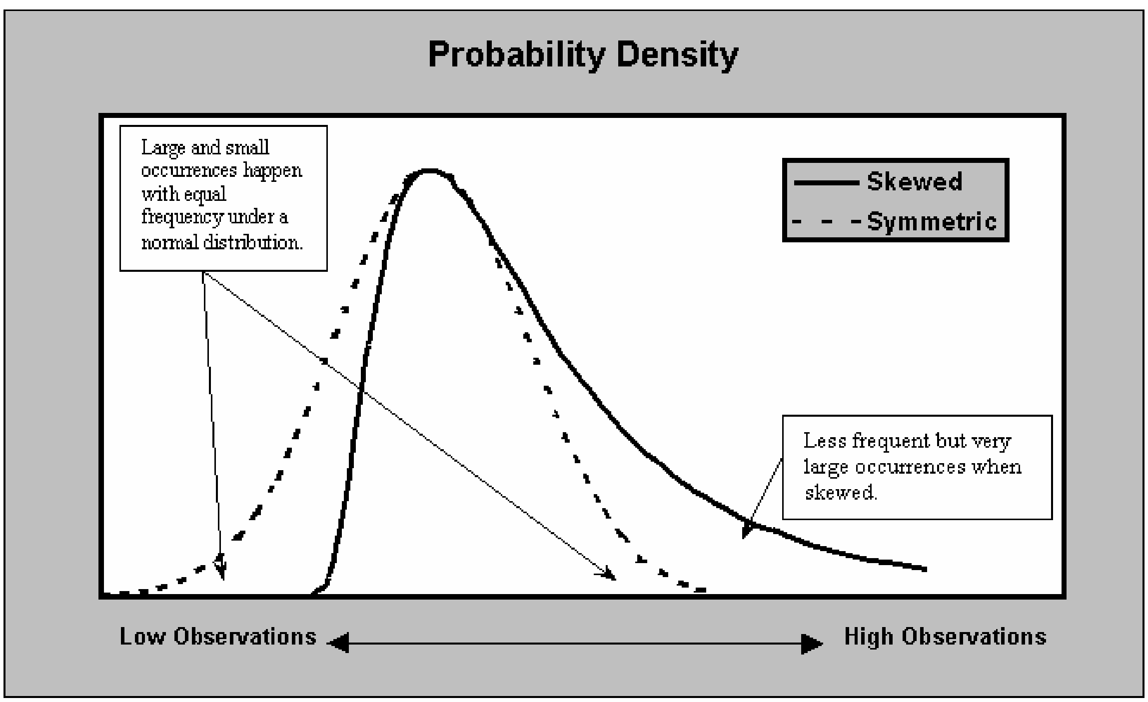
Hydroelectric generation risk parameters were taken from Henwood based on the work they performed for the Planning Margin study. The risk parameters were estimated to simulate hydro distribution patterns developed by PacifiCorp. The distributions were based on PacifiCorp's belief as to all possible outcomes of hydro events. For more information concerning the Planning Margin study and the hydroelectric generation distribution patterns see Appendix N.

Based on historic data and expected regulatory requirements, PacifiCorp has developed hydro generation forecasts for its owned and contracted units under varying levels of precipitation. PacifiCorp layered on top of that the probability of occurrence of each level of precipitation and developed data on weekly hydro generation for the western area under various exceedence levels. Henwood developed hydro volatility and mean reversion parameters that when subject to Monte Carlo draws generated a similar pattern of hydroelectric generation. The short term volatility parameter and mean reversion parameter for hydroelectric generation are given below in the table.

The Distribution Characteristics of the Stochastic Modeling Process

Since the price volatilities are assumed to be log-normally distributed and the load volatilities are assumed to be normally distributed, the distribution of PVRR is likely to be skewed to the right.[14] This effect is exacerbated by the non-linear dependence of PVRR on risk factors. This non-linear dependence is discussed further in Chapter 8. Understanding the nature of this skewness is important. On a year-to-year basis, skewed distributions imply the occurrence of many, slightly smaller than expected PVRRs. More importantly, they also imply that less frequent, dramatically high PVRRs can be expected. These higher values occur less frequently than the slightly smaller values contained in the skewed distribution. The graph in Figure G.1 illustrates the characteristics of a skewed distribution vs. a symmetrical distribution. This graph indicates that the higher values likely occur more often with a non-symmetrical distribution that is skewed to the right than with the symmetrical distribution.

Figure G.1 Probability Density



[14] A distribution is skewed to the right if there are more extremely high values than in the case of a symmetric distribution.

Short-Term Stochastic Parameters and Inputs

Short-Term Stochastic Inputs

Estimates of short-term volatility and mean-reversion parameters were developed statistically using ordinary least squares (OLS) regression on historical data. For historical natural gas prices and electricity prices, market hub daily spot prices published by Bloomberg were used. Columbia River basin data published by the University of Washington were used for hydro generation.

- Natural gas market prices at Sumas (June 2001 – December 2003) were used for western gas volatility, and an average of gas market prices at Opal and Sumas, during the same dates, were used for eastern gas price volatilities.
- On-Peak daily forward electricity market clearing prices were used for Mid-Columbia (Mid-C), COB, PV, and Four Corners (June 2001-2003).
- Historical loads for electric transmission areas California, Oregon, Idaho, Washington, Utah North and South, Idaho, and Wyoming were used (January 1994 – December 2003).
- PacifiCorp's hydro modeling team produced a hydro distribution of varying outflows upon which the stochastic parameters were chosen to reproduce this distribution. The data used in this analysis was PacifiCorp's owned and contracted hydro resources.

The short-term correlation parameter values were calculated as the simple correlation coefficient between the contemporaneous residuals of the regressions for each season. Doing so measures the correlation of the unexpected movements between each variable, i.e., gas prices, electric market prices, and load. Correlation values are used in the stochastic simulation to adjust the initial random draws for each variable in order to account for their correlation of unexpected movements. Correlations between each pair of stochastic variables were calculated using a statistical analysis estimation tool.

The statistical tool estimated the short-term volatility and mean-reversion parameters as follows. Let p = ln(P), where P is the spot value. The continuous time (as $\Delta t \to 0$) short-term mean-reversion process is:

$$p_t - p_{t-1} = (1 - e^{-\alpha})(\overline{p} - p_{t-1}) + \varepsilon_t$$

or

$$p_t = (1 - e^{-\alpha})\overline{p} + e^{-\alpha} \cdot p_{t-1} + \varepsilon_t$$

For daily (weekly, or other discrete) time data, the above process was estimated with OLS regression as an autoregressive lag 1 period (or AR(1)) equation:

$$p_t = a + b \cdot p_{t-1} + \varepsilon_t$$

The mean-reversion rate is then calculated from the AR(1) regression parameter:

$$\hat{\alpha} = 1 - \hat{b}$$

and the short-term volatility rate (on a daily basis) is equal to the standard error of the regression:

$\hat{\sigma} = \hat{s}$ where s is the standard error of the regression.

The volatility rate, then, is the residual volatility, after accounting for the mean reversion tendency, rather than total volatility.

The regression intercept ($\hat{a}$) coefficient is not needed, since it is only used in the calculation of the average value:

$$\bar{p} = \frac{\hat{a}}{1 - \hat{b}}$$

Short-Term Volatility Parameters

The tables below present the volatility parameters that are currently being used for the PacifiCorp stochastic assessments that were developed using the Simple Lognormal AR(1) Mean Reverting Model for price and hydroelectric generation inputs and a Simple Normal AR(1) Mean Reverting Model for the electric load.[15] The month designated is the beginning month for the shown parameter value. The parameter value continues until the next shown month in the table. Adjustments were made to the volatility parameters of gas and electric markets so that the volatility "band" is wide in the short-term and tends to be narrow in the long-term.[16] The volatility of these prices tends to have a decreasing term structure reflecting the "Samuelson effect"[17]. The "Alpha" column represents the short-term mean reversion parameter and the "Sigma" column represents the short-term volatility parameter.

Four Corners Electric Price

Season	Month	Alpha	Sigma
W	1	0.6726	0.077852
Sp	3	0.6347	0.081382
Su	6	0.3705	0.143374
F	9	0.5210	0.066429
W	12	0.6726	0.077852

Mid-Columbia Electric Prices

Season	Month	Alpha	Sigma
W	1	0.7334	0.075722
Sp	3	0.4832	0.090422
Su	6	0.2619	0.235901
F	9	0.4129	0.055998
W	12	0.7533	0.075722

[15] F = Fall, W = Winter, Sp = Spring, Sum = Summer

[16] Managing Energy Risk: A Non-technical Guide to Markets and Trading, John Wengler, PennWell Publishing Co., 2001, ppg. 104-5.

[17] Energy and Power Risk Management: New Developments in Modeling, Pricing, and Hedging, Alexander Eydeland and Krzysztof Wolyniec, John Wiley & Sons, Inc., 2003, pg. 91.

COB Electric Price

Season	Month	Alpha	Sigma
W	1	0.6570	0.078329
Sp	3	0.7844	0.092598
Su	6	0.2491	0.149446
F	9	0.5643	0.060818
W	12	0.6570	0.078329

Palo Verde Electric Prices

Season	Month	Alpha	Sigma
W	1	0.7524	0.075406
Sp	3	0.6316	0.089392
Su	6	0.3491	0.13349
F	9	0.6343	0.04901
W	12	0.7524	0.075406

West Natural Gas Price

Season	Month	Alpha	Sigma
W	1	0.1046	0.060273
Sp	3	0.1626	0.063402
Su	6	0.1844	0.050535
F	9	0.2057	0.044589
W	12	0.1444	0.060273

East Natural Gas Prices

Season	Month	Alpha	Sigma
W	1	0.1150	0.064591
Sp	3	0.1008	0.039944
Su	6	0.1462	0.06585
F	9	0.1859	0.063796
W	12	0.1150	0.064591

Utah North & South Load

Season	Month	Alpha	Sigma
W	1	0.462	0.0174
Sp	3	0.552	0.0216
Su	6	0.409	0.0334
F	9	0.553	0.0242
W	12	0.452	0.0238

Idaho Load

Season	Month	Alpha	Sigma
W	1	0.265	0.0405
Sp	3	0.291	0.0344
Su	6	0.172	0.0299
F	9	0.264	0.0323
W	12	0.350	0.0330

Wyoming Load

Season	Month	Alpha	Sigma
W	1	0.432	0.0175
Sp	3	0.298	0.0192
Su	6	0.325	0.0172
F	9	0.392	0.0187
W	12	0.450	0.0187

Washington Load

Season	Month	Alpha	Sigma
W	1	0.286	0.0416
Sp	3	0.495	0.0334
Su	6	0.423	0.0404
F	9	0.435	0.0353
W	12	0.328	0.0418

Oregon/California Load

Season	Month	Alpha	Sigma
W	1	0.347	0.0312
Sp	3	0.497	0.0295
Su	6	0.409	0.0277
F	9	0.483	0.0296
W	12	0.384	0.0390

Hydroelectric

Month	Alpha	Sigma
1	0.1056	0.1953
2	0.1169	0.2056
3	0.0777	0.1558
4	0.0803	0.1584
5	0.0777	0.1558
6	0.0803	0.1584
7	0.0777	0.1558
8	0.1394	0.1229
9	0.1440	0.1249
10	0.1394	0.1229
11	0.1440	0.1249
12	0.1056	0.1953

Short-Term Correlation Parameters

The tables below present the short-term correlation parameters that are currently being used for the PacifiCorp stochastic assessments. The correlation between hydroelectric generation and the other stochastic variables is assumed to be zero since there is no known dependence between available hydroelectric generation and these other variables, e.g., electric market prices and natural gas prices. The correlations between the various combinations of electric market prices and gas prices from the mean reversion models have been adjusted such that the correlations of expected residuals of these combinations are in an acceptable range in the long-term.

Load Correlations

Utah North

Month	Idaho	Utah South	Washington	West Main	Wyoming
1	0.401	0.243	0.257	0.258	0.415
3	0.289	0.243	0.142	0.179	0.274
6	0.146	0.243	0.140	0.150	0.374
9	0.307	0.243	0.210	0.242	0.307
12	0.309	0.243	0.396	0.398	0.506

Idaho

Month	Utah South	Washington	West Main	Wyoming
1	0.147	0.261	0.264	0.334
3	0.147	0.204	0.236	0.209
6	0.147	0.056	0.043	0.171
9	0.147	0.247	0.253	0.306
12	0.147	0.256	0.323	0.401

Utah South

Month	Washington	West Main	Wyoming
1	0.284	0.228	0.230
3	0.284	0.228	0.230
6	0.284	0.228	0.230
9	0.284	0.228	0.230
12	0.284	0.228	0.230

Washington

Month	West Main	Wyoming
1	0.733	0.375
3	0.699	0.181
6	0.809	0.130
9	0.751	0.195
12	0.778	0.345

Oregon/California

Month	Wyoming
1	0.313
3	0.156
6	0.126
9	0.234
12	0.342

Price Correlations

COB

Month	Four Corners	MidC	Palo Verde	NG - East	NG – West
1	0.889	0.966	0.893	0.068	0.069
3	0.768	0.826	0.792	0.271	0.328
6	0.757	0.868	0.797	0.265	0.308
9	0.733	0.787	0.760	0.134	0.193
12	0.889	0.966	0.893	0.068	0.069

Four Corners

Month	MidC	Palo Verde	NG - East	NG – West
1	0.849	0.943	0.055	0.071
3	0.670	0.950	0.275	0.352
6	0.674	0.928	0.165	0.209
9	0.787	0.917	0.109	0.171
12	0.849	0.943	0.055	0.071

MidC

Month	Palo Verde	NG – East	NG – West
1	0.844	0.060	0.060
3	0.709	0.300	0.294
6	0.724	0.410	0.442
9	0.659	0.228	0.244
12	0.844	0.060	0.060

Palo Verde

Month	NG – East	NG – West
1	0.063	0.062
3	0.290	0.370
6	0.180	0.229
9	0.140	0.195
12	0.063	0.062

NG – East

Month	NG – West
1	0.978
3	0.784
6	0.909
9	0.882
12	0.978

Load/Price Correlations

Idaho Load

Month	COB	Four Corners	MidC	Palo Verde	NG - East	NG - West
1	0.0363	0.0967	0.0241	0.0888	0.0155	0.0153
3	0.0147	0.0705	0.0075	0.0599	0.0245	0.0268
6	0.0452	0.0852	0.0335	0.0888	0.0037	0.0086
9	0.0501	0.0989	0.0375	0.1030	0.0284	0.0352
12	0.0363	0.0967	0.0241	0.0888	0.0155	0.0153

Utah North Load

Month	COB	Four Corners	MidC	Palo Verde	NG - East	NG - West
1	0.0514	0.1207	0.0341	0.1068	-0.0303	-0.0268
3	0.0208	0.1227	0.0180	0.0978	-0.0557	-0.0427
6	0.0983	0.1426	0.0700	0.1327	-0.0753	-0.0640
9	0.0543	0.1170	0.0376	0.1041	-0.0655	-0.0517
12	0.0514	0.1207	0.0341	0.1068	-0.0303	-0.0268

Utah South Load

Month	COB	Four Corners	MidC	Palo Verde	NG - East	NG - West
1	0.0514	0.1207	0.0341	0.1068	0.2000	0.0700
3	0.0208	0.1227	0.0180	0.0978	-0.0200	-0.1100
6	0.0983	0.1426	0.0700	0.1327	-0.1600	-0.0800
9	0.0543	0.1170	0.0376	0.1041	-0.1300	-0.2000
12	0.0514	0.1207	0.0341	0.1068	0.2500	0.0790

Washington Load

Month	COB	Four Corners	MidC	Palo Verde	NG - East	NG - West
1	0.1094	0.0657	0.1080	0.0552	0.0967	0.0686
3	0.0909	0.0526	0.1050	0.0370	0.1423	0.1034
6	0.0001	0.0015	0.0283	-0.0321	0.0158	-0.0107
9	0.0941	0.0503	0.0988	0.0422	0.0347	0.0012
12	0.1094	0.0657	0.1080	0.0552	0.0967	0.0686

West Main Load

Month	COB	Four Corners	MidC	Palo Verde	NG - East	NG - West
1	0.1171	0.1014	0.1471	0.0842	0.1031	0.0654
3	0.1467	0.1298	0.1856	0.1114	0.1529	0.1058
6	0.0403	0.0638	0.0859	0.0254	0.0669	0.0294
9	0.1072	0.1043	0.1390	0.0899	0.0624	0.0224
12	0.1171	0.1014	0.1471	0.0842	0.1031	0.0654

Wyoming Load

Month	COB	Four Corners	MidC	Palo Verde	NG - East	NG - West
1	0.0035	0.0305	-0.0266	0.0149	0.0432	0.0174
3	-0.0239	-0.0408	-0.0489	-0.0424	0.0619	0.0265
6	0.0309	0.0645	0.0031	0.0490	0.0124	-0.1662
9	0.0199	0.0468	-0.0095	0.0357	0.0278	0.0041
12	0.0035	0.0305	-0.0266	0.0149	0.0432	0.0174

Stochastic Parameters: Long Term

Estimating longer-term volatility and the correlation of variables for electricity and natural gas prices are somewhat more subjective than estimating the short-term parameters for several reasons. First, wholesale market prices for electricity are not available for the twenty or more years that would be necessary to statistically estimate its long-run volatility. Regulation of natural gas wellhead and transmission rates in past years also make the available long-term prices for natural gas a more challenging subject for simulation.

For natural gas, the starting point for annual long-term volatility was 14.51% as adopted from econometric analysis by Pindyck (Energy Journal, 1998), based on data from 1970 through 1996. This percentage was converted to a daily rate by dividing by the square root of 365. These values were adjusted so that the volatility "band" is wide in the short-term and tends to be narrow in the long-term.[18]

Lacking long-term data for wholesale electricity prices, we assume the same starting point for annual long-term volatility for electricity. This assumption may be justified by noting that electricity is a manufactured commodity whose long-run price is largely determined by the cost of fuel. These values were also adjusted to reflect the desired shape of the volatility range.

The long-term correlations between each pair of gas and electric prices, gas and gas prices, and electric and electric prices were assumed to be approximately between 0.94 and 0.98.

For loads, the following long-term volatilities in Table G.1 were used based on standard deviation of the absolute value of the rate of growth for each transmission area from 1989 through 2003.

Table G.1 – Long Term Load Volatilities

	Wyoming	Washington	Oregon/ California	Idaho	Utah North	Utah South
L-T Volatility	4.3%	2.5%	1.8%	3.2%	1.1%	1.1%

The long-term correlation for loads between areas was determined by the residuals of a trend regression equation with annual periodicity for each area. These residuals represent the annual "shocks" for each area. These "shocks" could be due to economic growth occurring within an area, extreme weather conditions within an area, or a variety of other reasons. The correlations of these residuals measure the dependence between areas with respect to these "shocks". Table G.2. contains the values of the long-term correlations with respect to load in an upper diagonal matrix format.

Table G.2 – Long Term Load Correlations

	Wyoming	Washington	Oregon/ California	Idaho	Utah North	Utah South
Wyoming		-0.163	-0.355	0.605	-0.07	-0.07
Washington			0.792	-0.547	0.461	0.461
Oregon/ California				-0.704	0.348	0.348
Idaho					0.107	0.107
Utah North						0.95

[18] Wengler, ppg. 104-5.

The long term volatility for hydroelectric generation is assumed to be zero since only existing and known additional hydroelectric plants are considered.

Determination of the Appropriate Number of Iterations

If classical statistical analysis is not implemented, then the appropriate number of iterations, i.e., sample size, is purely subjective. The ideal state is to draw a sample such that a certain level of confidence that the true mean is within an interval is maintained. The length of the interval is expressed as a percent of the sample mean. The formula used to determine the appropriate number of iterations is

$$n = [(z_{\alpha/2} * \sigma)/E]^2$$

where $z_{\alpha/2}$ is the value on the standard normal distribution such that there is $1\text{-}\alpha/2$ probability of exceeding that value, σ is the population standard deviation usually estimated by the sample standard deviation, and E is the interval length usually estimated as a percent of the sample mean.[19] Using this formula gives us a sample size such that we are $(1 - \alpha)100\%$ confident that the true mean value is within ± E, e.g., ± 5% of the true mean value.

In practice the following steps were followed to determine and validate that the sample size is sufficient.

1) Perform initial stochastic runs of all selected portfolios using at least 30 iterations. For this exercise 100 iterations were performed.
2) Calculate sample sizes for each portfolio varying $(1\text{-}\alpha)100\%$ and E. Determine the appropriate level $(1\text{-}\alpha)100\%$ and E.
3) Take the maximum sample size over all selected portfolios for the level of $(1\text{-}\alpha)100\%$ and E determined in step 2.
4) Use the maximum sample size (iterations) and re-do the stochastic runs.
5) Evaluate (recalculate) the appropriate sample sizes varying $(1\text{-}\alpha)100\%$ and E from the new stochastic runs.[20]
6) If the sample size, level of $(1\text{-}\alpha)100\%$, and the level of E are satisfactory, then stop. If the sample size, level of $(1\text{-}\alpha)100\%$, and the level of E are not satisfactory, then increasing the number of iterations is necessary.
7) Increase the number of iterations, re-do stochastic runs, and repeat steps 5 through 7 until the sample size, level of $(1\text{-}\alpha)100\%$, and the level of E are satisfactory.

Based on a preliminary stochastic run with large volatility parameters the maximum sample size across all portfolios was 97. The value of 97 satisfied the minimal 90% level of confidence of being within ±10% of the mean. So, 100 iterations for the second stochastic run were considered an appropriate starting point. Each selected portfolio was run for the 'All-In' case and for the 'Spark Spread' case using 100 iterations. The maximum number of iterations across all portfolios for the 'All-In' case at varying levels of $(1\text{-}\alpha)100\%$ and E are given in Table G.3.

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[19] Modern Elementary Statistics, 7th ed., John E. Freund, 1988, pg. 277.

[20] The new stochastic runs will generate a different mean and standard deviation for each portfolio from the initial stochastic run which will result in a different set of possible sample sizes.

Table G.3 – Number of Maximum Iterations for the 'All-In' Case

Level of Confidence	Percent of Mean	Number of Iterations
90%	±10	9
95%	±10	13
90%	±5	37
95%	±5	52
95%	±3	144
95%	±4	81
95%	±3.5	106
99%	±5	90

Since the stochastic run had mean and standard deviation values such that 100 iterations exceeds either the 95% confidence level of being within ±4% of the mean and the 99% confidence level of being within ±5% of the mean, it was concluded that 100 iterations was satisfactory.

Using the same 100 iterations for the 'Spark Spread' case, the maximum number of iterations across all selected portfolios at varying levels of (1-α)100% and E are given in Table G.4.

Table G.4 – Number of Maximum Iterations for the 'Spark Spread' Case

Level of Confidence	Percent of Mean	Number of Iterations
90%	±10	6
95%	±10	8
90%	±5	23
95%	±5	32
95%	±3	89
95%	±4	50
95%	±2.5	128
99%	±5	55
99%	±3.5	113
99%	±4	86

Since the stochastic runs had mean and standard deviation values such that 100 iterations exceeds either the 95% confidence level of being within ±3% of the mean and the 99% confidence level of being within ±4% of the mean, it was concluded that 100 iterations was satisfactory.[21]

[21] Each case was considered satisfactory because the confidence levels were substantially greater than the initial 90% level and the "percent of mean" was substantially less than the initial ±10%.

Input Values Based on 100 Iterations

The input values of market electric price, natural gas prices, and load are shown in the following graphs. Figures G.1 and G.2 illustrate the 100 iterations used in the stochastic analysis for the Palo Verde and Mid-Columbia markets for calendar years 2006 through 2024.

Figure G.1 – Palo Verde Average Annual Electric Prices – 100 Iterations

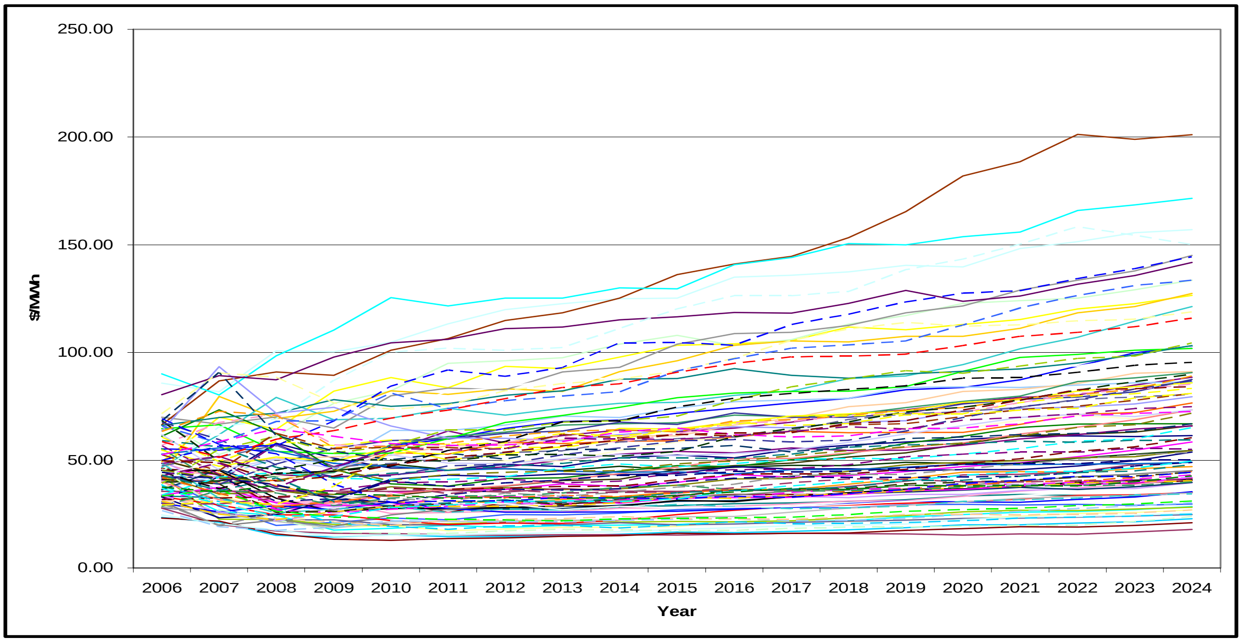
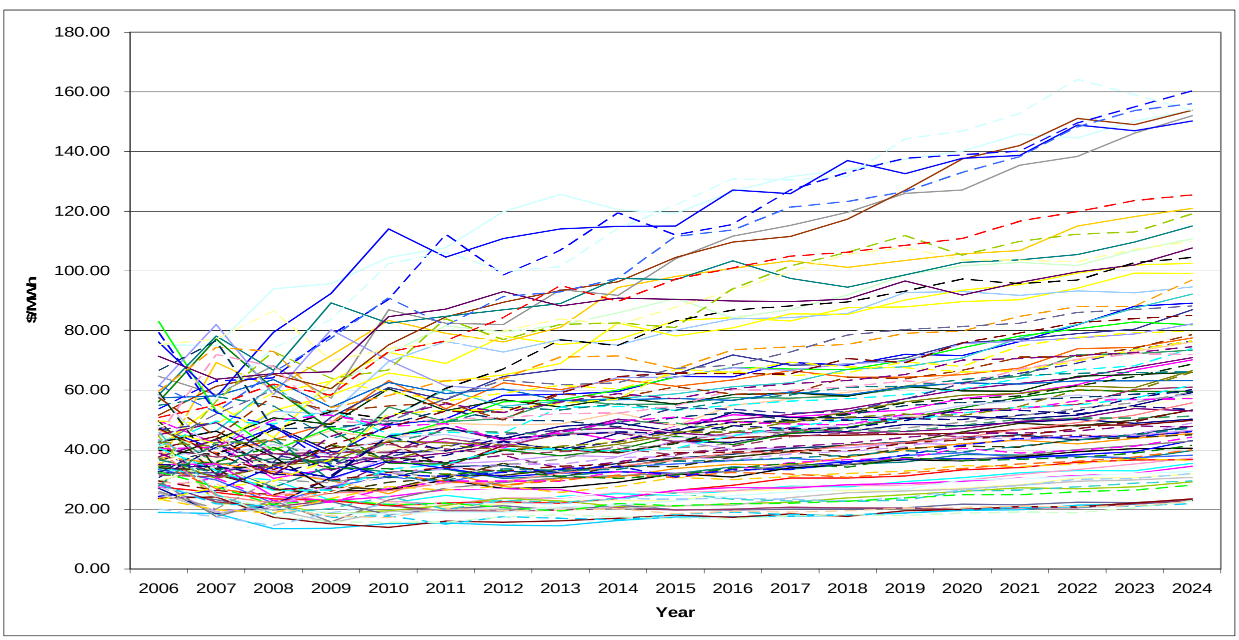


Figure G.2 – Mid-Columbia Annual Average Electric Prices – 100 Iterations



Figures G.3 and G.4 illustrate the 100 iterations for the west and east natural gas prices used in the stochastic analysis on a calendar year basis.

Figure G.3 – Annual Average West Natural Gas Prices – 100 Iterations

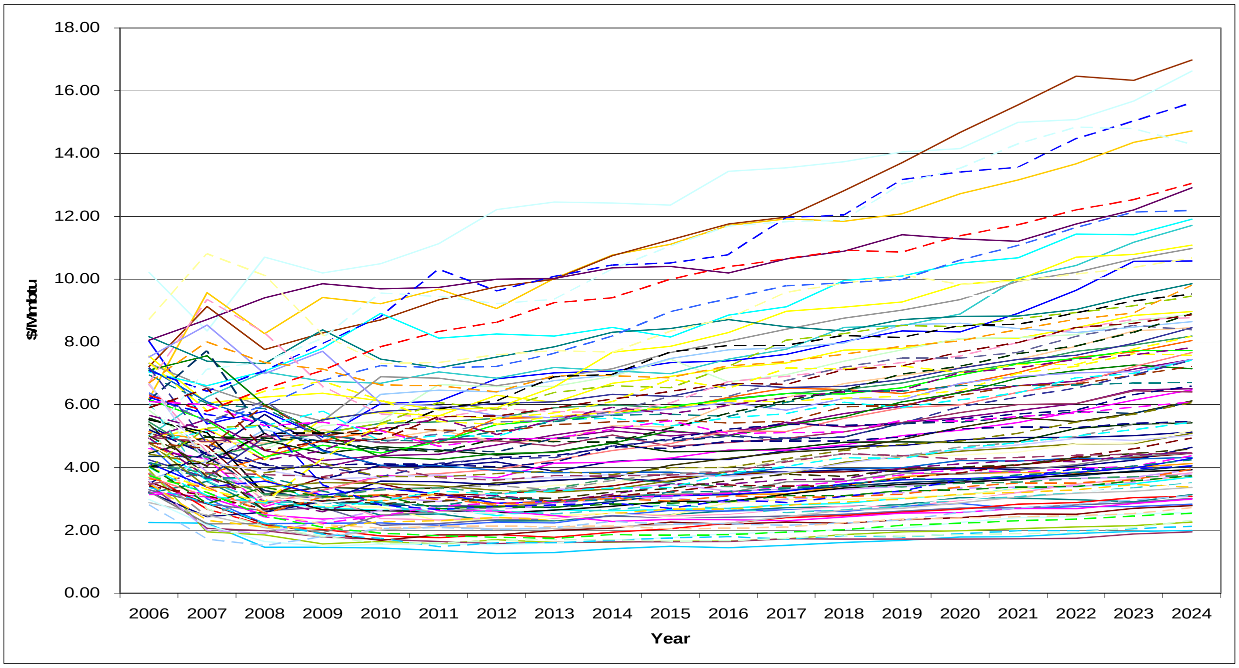
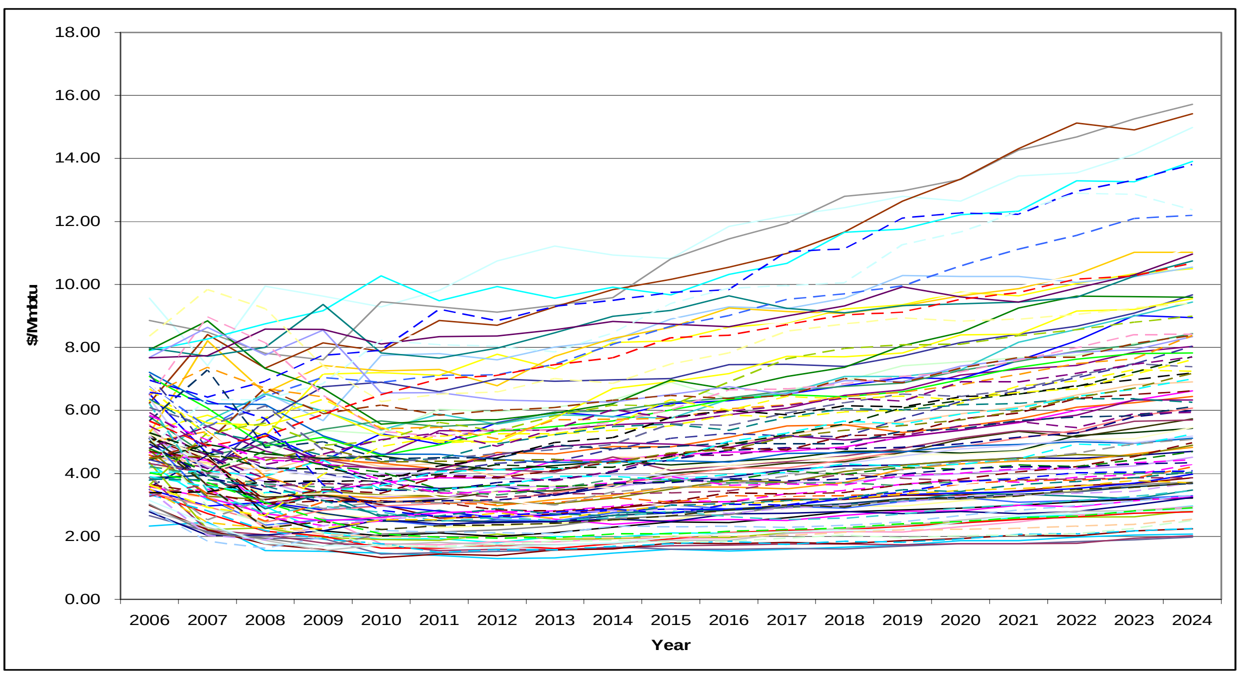


Figure G.4 – Annual Average East Natural Gas Prices – 100 Iterations



Figures G.5 and G.6 illustrate the 100 iterations for the east and west control area average hourly loads for each calendar year, i.e., MWa, used in the stochastic analysis.

Figure G.5 – East Control Area Loads – 100 Iterations

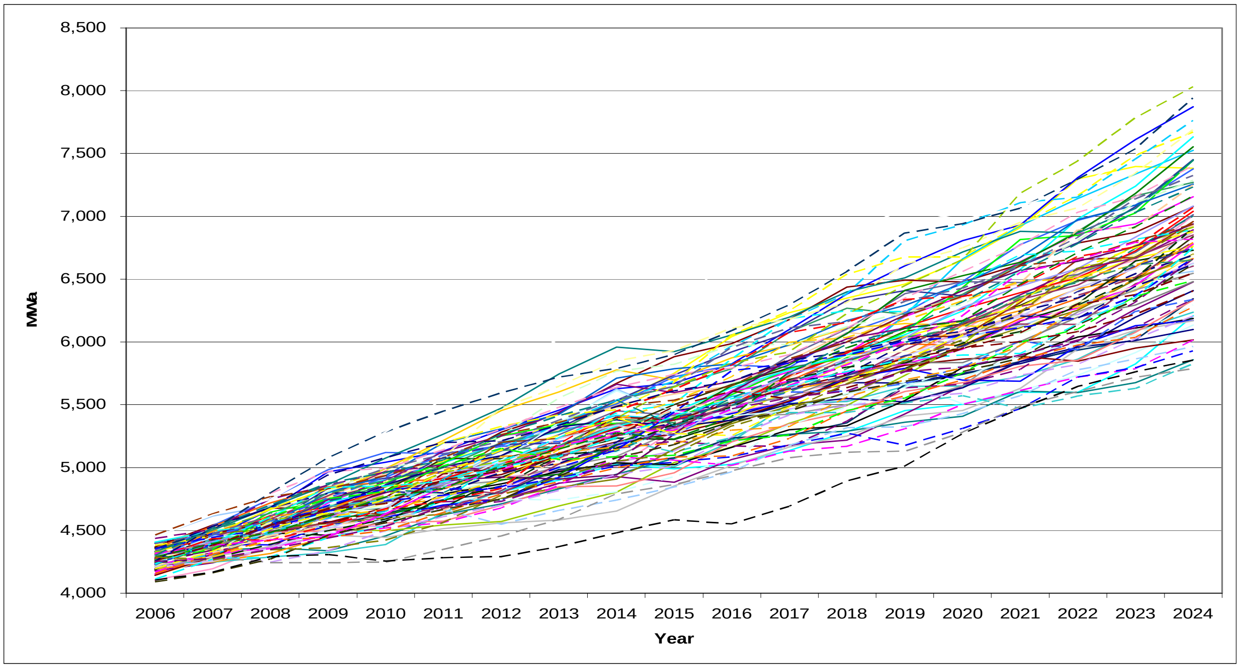
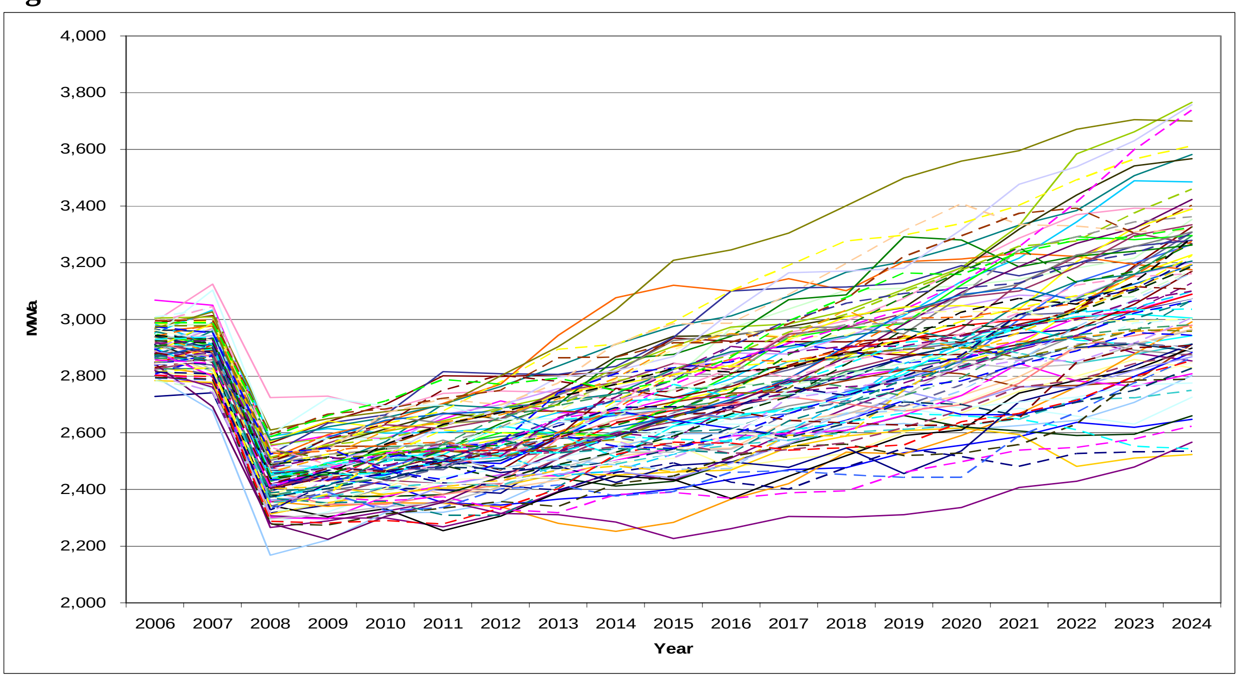


Figure G.6 – West Control Area Loads – 100 Iterations



SCENARIO ANALYSIS

Two types of scenarios were analyzed for this IRP. The first type was the CO_2 emissions charges scenario which evaluated emissions charges at four different levels in addition to the base case. The second type of scenario was the high price scenario which evaluated higher prices of natural gas and electric market prices. The following sections discuss the selection and methodology behind each of the scenarios.

CO_2 Scenario Assumptions

The base case CO_2 emissions allowance charge is assumed to be $8 (2008 dollars) per ton starting in 2012. Further it is assumed that there is a 50% probability of the emissions allowance charge beginning in 2010 and a 75% probability of the charge beginning in 2011. As a result of these assumptions the $8 value is multiplied by the probability of occurrence for these years. Associated with this CO_2 emissions allowance charge assumption are the NO_X, SO_2, and H_g (mercury) price adders, as well as the natural gas and electric power price assumptions.

Four CO_2 emissions allowance charge scenarios were analyzed during this IRP cycle. Three of the CO_2 scenarios are in compliance with Oregon Order 93-695 dated May 17, 1993. The Order requires that IRP analysis be performed with the CO_2 emissions allowance charges varying at values of $10, $25, and $40 per ton in 1990 dollars. An additional scenario was performed during this IRP cycle which set the value of the CO_2 emissions allowance charges at $0 per ton in order to measure the impact of no emissions charges. For each scenario changes occur in the NO_X price adder, SO_2 price adder, natural gas price, and electric power price. The Hg emissions allowance charge is not assumed to change in any of the four scenarios. For each scenario the same start year of CY 2012 is assumed and similar assumptions concerning the probabilities of occurrence in CY 2010 and CY 2011 are assumed.

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. (Additional discussions of these scenarios are contained in Chapter 8 Results.)

$8 CO_2 Emissions Allowance Charge (Base Case)

In Table G.5 values of the emissions charges are illustrated for the $8 per ton base case.

Table G.5 – Base Case Emissions Charges

Calendar Year	SO_2 ($/ton)	NO_X ($/ton)	Hg ($/lb)	CO_2 ($/ton)
2005	395	--	--	--
2006	481	--	--	--
2007	559	--	--	--
2008	648	--	--	--
2009	753	--	--	--

Calendar Year	SO_2 ($/ton)	NO_X ($/ton)	Hg ($/lb)	CO_2 ($/ton)
2010	877	2,105	40,934	4.19
2011	899	2,158	41,958	6.45
2012	921	2,210	42,965	8.80
2013	944	2,265	44,039	9.02
2014	967	2,321	45,140	9.25
2015	997	2,393	46,539	9.54
2016	1,028	2,468	47,982	9.83
2017	1,061	2,547	49,517	10.15
2018	1,096	2,631	51,151	10.48
2019	1,133	2,720	52,890	10.84
2020	1,172	2,813	54,689	11.21
2021	1,212	2,908	56,548	11.59
2022	1,254	3,010	58,527	11.99
2023	1,298	3,115	60,576	12.41
2024	1,343	3,224	62,696	12.85
2025	1,391	3,337	64,890	13.30

$0 CO_2 Emissions Allowance Charge

In Table G.6 the values of the emissions charges are illustrated for the $0 per ton scenario.

Table G.6 – $0 CO_2 Scenario Emissions Charges

Calendar Year	SO_2 $/ton	NO_X $/ton	CO_2 $/ton
2005	395	--	--
2006	481	--	--
2007	559	--	--
2008	686	--	--
2009	797	--	--
2010	928	2,105	0.00
2011	951	2,158	0.00
2012	974	2,210	0.00
2013	998	2,265	0.00
2014	1,023	2,321	0.00
2015	1,055	2,393	0.00
2016	1,088	2,468	0.00
2017	1,123	2,547	0.00
2018	1,160	2,631	0.00
2019	1,199	2,720	0.00
2020	1,240	2,813	0.00
2021	1,282	2,908	0.00
2022	1,327	3,010	0.00
2023	1,373	3,115	0.00
2024	1,421	3,224	0.00
2025	1,471	3,337	0.00

\$10 CO_2 Emissions Allowance Charge

In Table G.7 the values of the emissions charges are illustrated for the \$10 per ton scenario.

Table G.7 – \$10 CO_2 Scenario Emissions Charges

Calendar Year	SO_2 \$/ton	NO_X \$/ton	CO_2 \$/ton
2005	395	--	--
2006	481	--	--
2007	559	--	--
2008	584	--	--
2009	679	--	--
2010	791	2105	7.45
2011	811	2158	11.45
2012	830	2210	15.64
2013	851	2265	16.03
2014	872	2321	16.43
2015	900	2393	16.94
2016	927	2468	17.46
2017	957	2547	18.02
2018	989	2631	18.62
2019	1022	2720	19.25
2020	1057	2813	19.91
2021	1093	2908	20.58
2022	1131	3010	21.30
2023	1171	3115	22.05
2024	1212	3224	22.82
2025	1254	3337	23.62

\$25 CO_2 Emissions Allowance Charge

In Table G.8 the values of the emissions charges are illustrated for the \$25 per ton scenario.

Table G.8 – \$25 CO_2 Scenario Emissions Charges

Calendar Year	SO_2 \$/ton	NO_X \$/ton	CO_2 \$/ton
2005	395	--	--
2006	481	--	--
2007	559	--	--
2008	441	--	--
2009	512	--	--
2010	596	345	18.62
2011	611	354	28.63
2012	626	362	39.10
2013	642	371	40.07
2014	658	381	41.08
2015	678	393	42.35
2016	699	405	43.66
2017	722	418	45.06

Calendar Year	SO_2 $/ton	NO_X $/ton	CO_2 $/ton
2018	745	431	46.55
2019	771	446	48.13
2020	797	461	49.76
2021	824	477	51.46
2022	853	494	53.26
2023	883	511	55.12
2024	914	529	57.05
2025	946	547	59.05

$40 CO_2 Emissions Allowance Charge

In Table G.9 the values of the emissions charges are illustrated for the $40 per ton scenario.

Table G.9 – $40 CO_2 Scenario Emissions Charges

Calendar Year	SO_2 $/ton	NO_X $/ton	CO_2 $/ton
2005	395	--	--
2006	481	--	--
2007	559	--	--
2008	257	--	--
2009	299	--	--
2010	348	345	29.80
2011	357	354	45.82
2012	366	362	62.55
2013	375	371	64.12
2014	384	381	65.72
2015	396	393	67.76
2016	408	405	69.86
2017	421	418	72.09
2018	435	431	74.47
2019	450	446	77.01
2020	465	461	79.62
2021	481	477	82.33
2022	498	494	85.21
2023	515	511	88.19
2024	533	529	91.28
2025	552	547	94.48

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 G.7 and G.8 show plots of east and west market prices for each CO_2 case on a calendar year basis. 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. Figures G.9 and G.10 show the natural gas prices for the east and the west for each scenario and the base case on a calendar year basis.

Figure G.7 – Palo Verde Average Annual Forward Prices for the CO_2 Scenarios

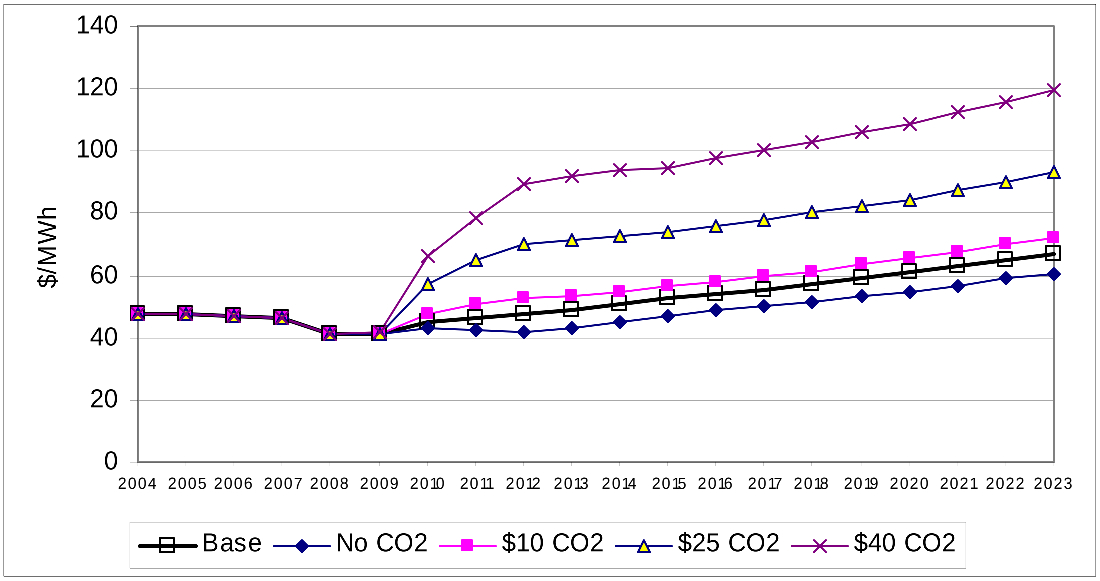


Figure G.8 – Mid-Columbia Average Annual Forward Prices for the CO_2 Scenarios

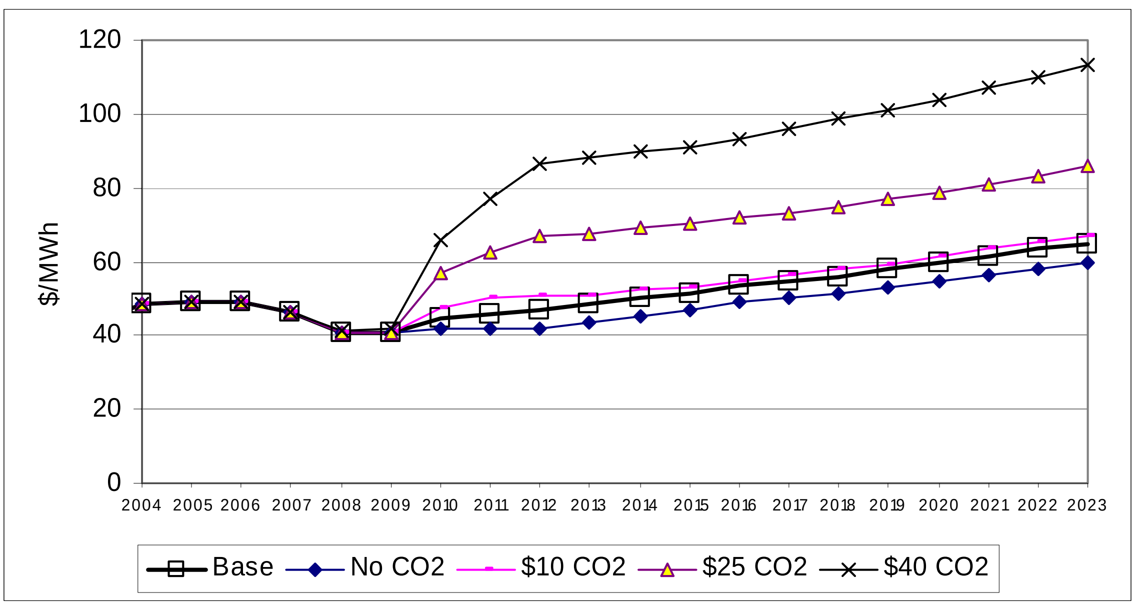


Figure G.9 – West Average Annual Forward Gas Prices for the CO_2 Scenarios

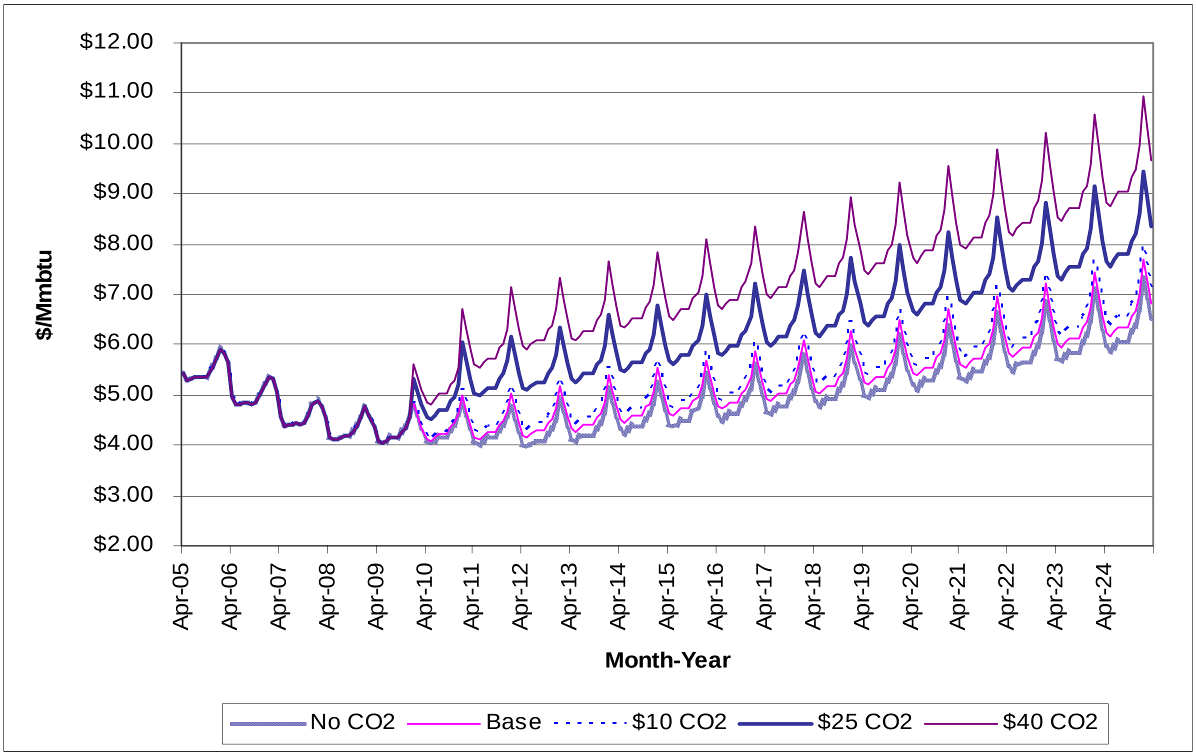
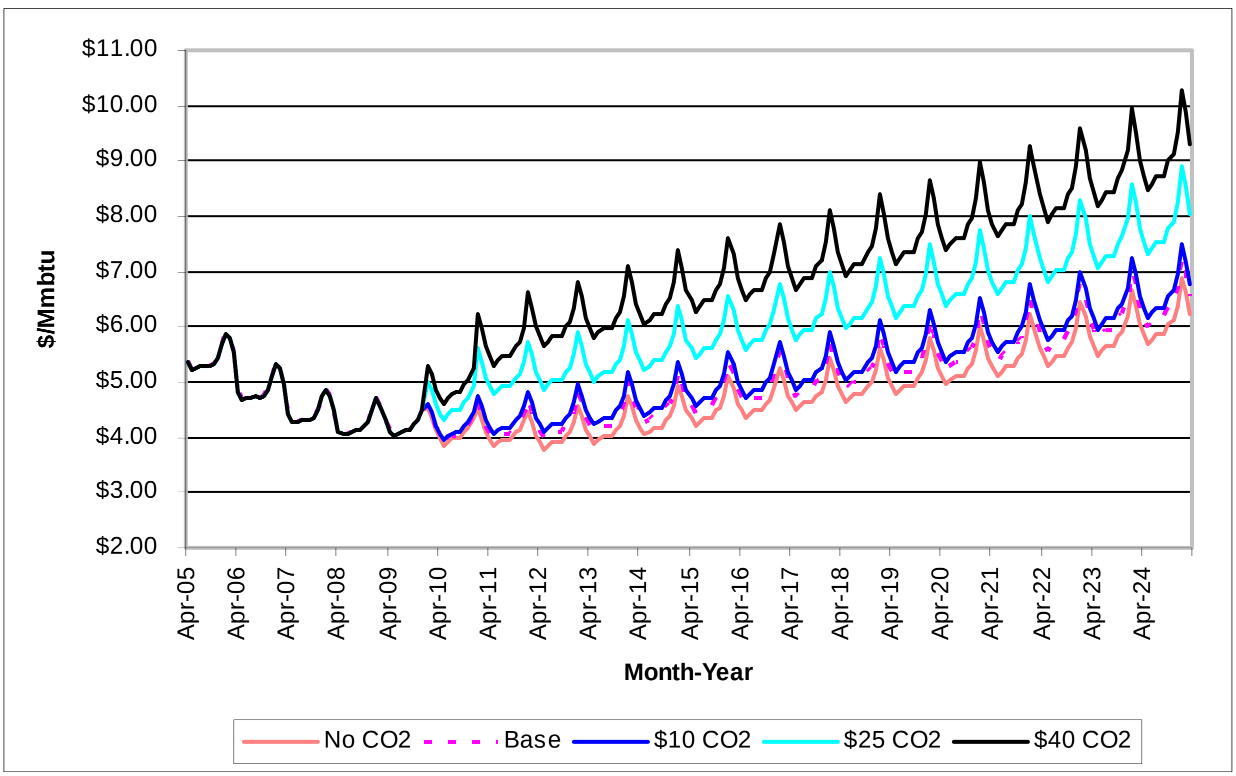


Figure G.10 – East Average Annual Forward Gas Prices for the CO_2 Scenarios



High Gas Price Scenario Assumptions

The goal of this scenario is to test selected Portfolios' sensitivity to a large fundamental increase in gas prices. 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. The east and west natural gas price comparisons are shown in Figures G.11 and G.12.

Figure G.11 – East Average Annual Forward Gas Prices – High Scenario

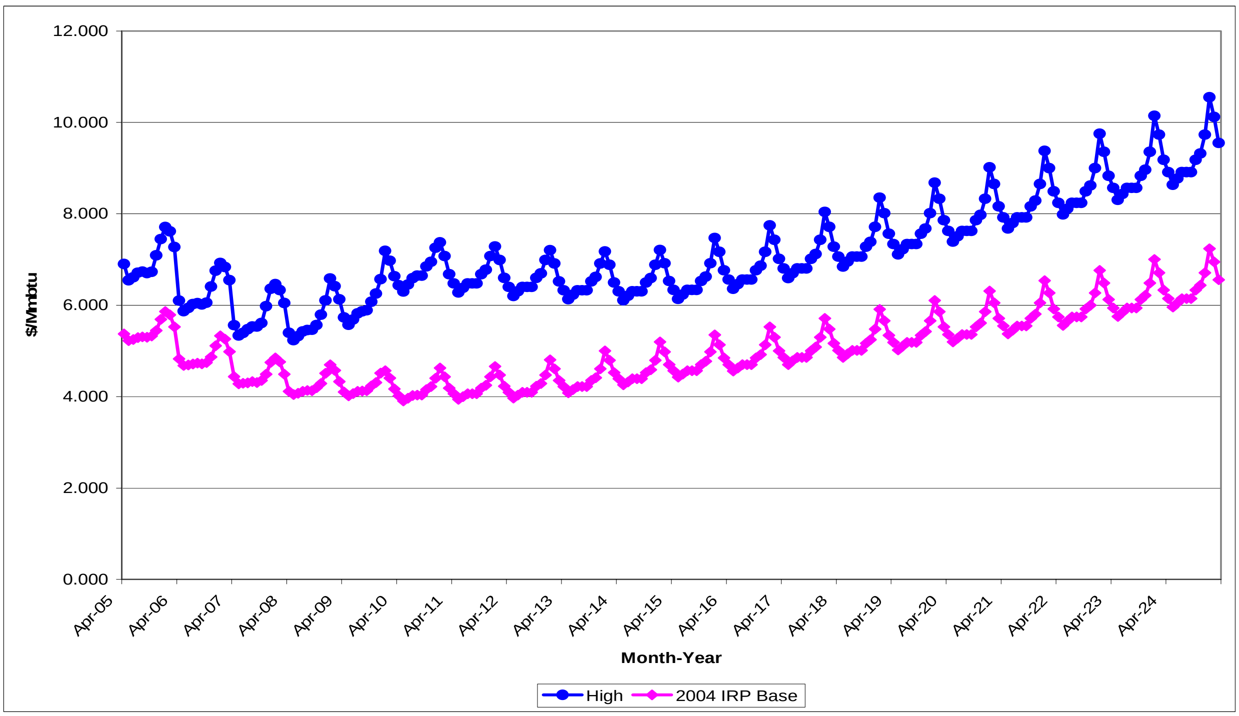
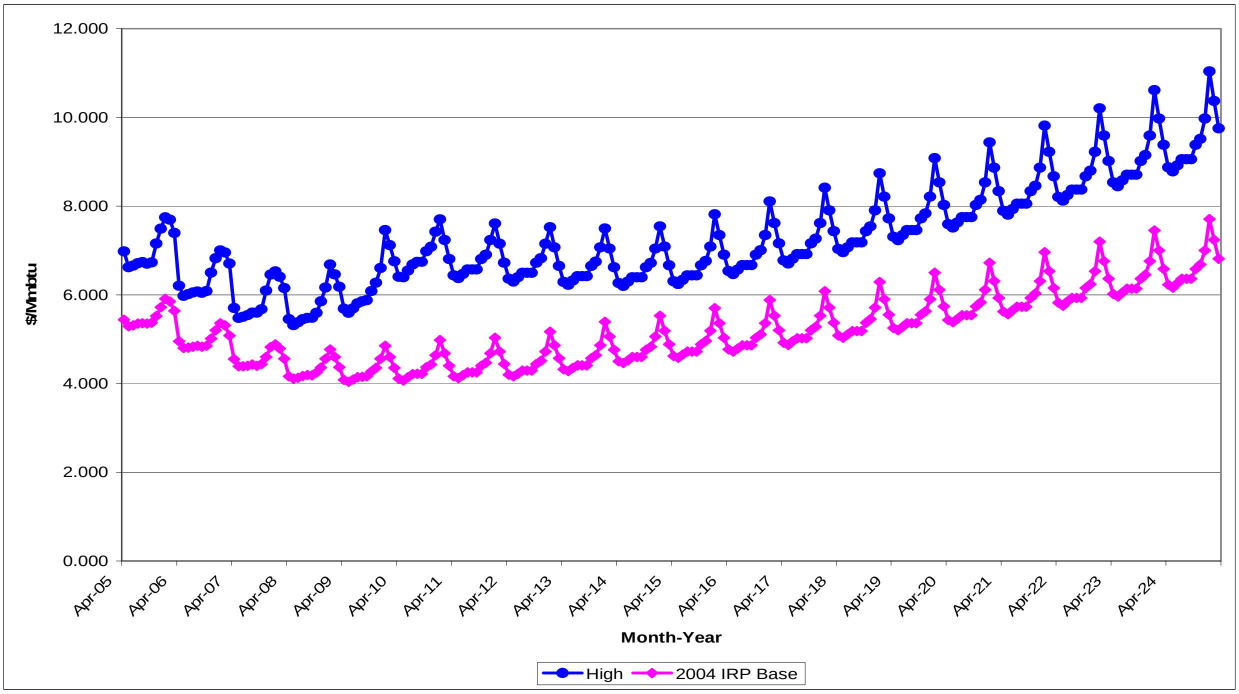


Figure G.12 – West Average Annual Forward Gas Prices – High Scenario



The base and high average market clearing electric prices are shown for Palo Verde and Mid Columbia in Figures G.13 and G.14, respectively, on a calendar year basis.

Figure G.13 – Palo Verde Average Annual Forward Prices – High Scenario

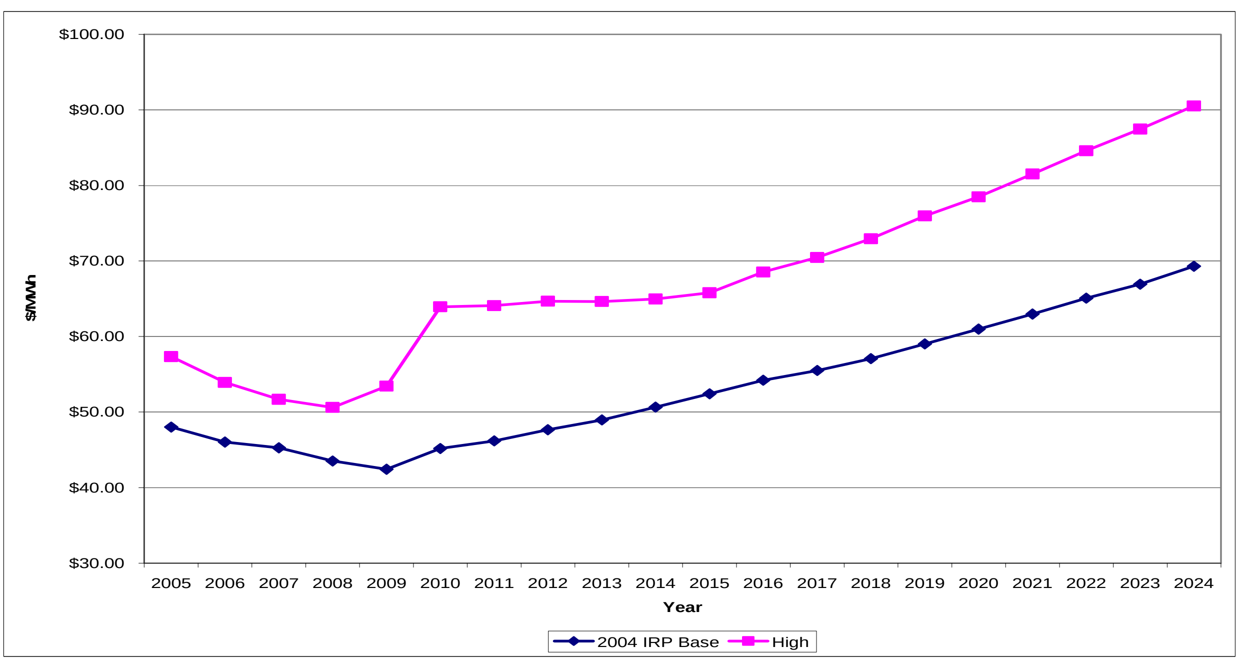
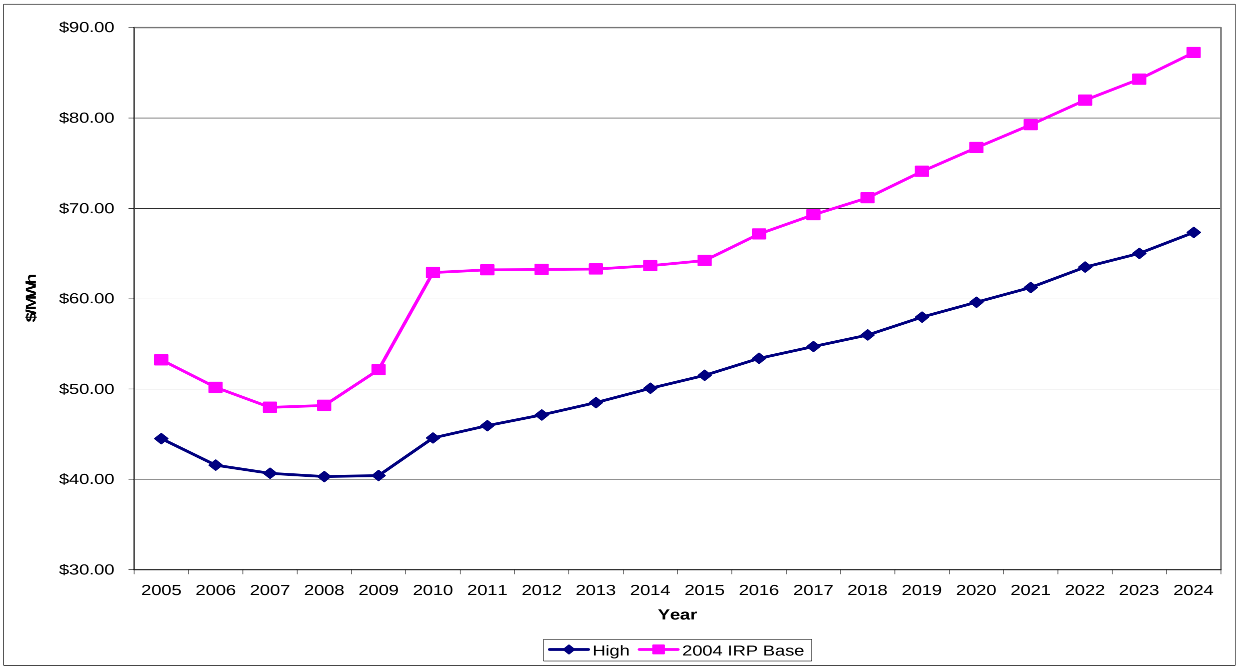


Figure G.14 – Mid-Columbia Average Annual Forward Prices – High Scenario



APPENDIX H – MODEL DESCRIPTIONS

INTRODUCTION

This section provides detailed descriptions of the models used in the 2004 IRP. Models described include the MIDAS Gold Transact Analyst (MIDAS), the MARKETSYM least-cost dispatch model and the new Capacity Expansion Model (CEM). The CEM performs automated capacity expansions and MIDAS derives forward market prices. This information is input into MARKETSYM, which then performs a detailed hourly dispatch of the PacifiCorp system for testing portfolios.

Recently these models changed ownership. MIDAS was owned by MS Gerber while MARKETSYM and the CEM were owned by Henwood Energy Services. Both of these companies were acquired by Global Energy Services bringing the three models under a single ownership. Based in Boulder, Colorado, Global Energy Services works with over 400 clients in the energy business. They provide solutions focusing on operations, strategic planning, market analytics, trading and enterprise portfolio management. This consolidation should provide PacifiCorp with a reliable source of support and upgrades for the described modeling systems.

MIDAS

Every market valuation of generation resources is significantly influenced by the underlying forecast(s) of wholesale market prices. The commodity nature of the wholesale electric market anticipates that reasonable, well-informed parties will possess different market expectations. The challenge of this IRP process is to find a path that best achieves the identified objectives irrespective of the exact level of market prices in the future. The following section provides an overview of the MIDAS model.

MIDAS Overview

PacifiCorp uses MIDAS Gold Transact Analyst, an hourly, chronological market clearing price dispatch model. The following are major characteristics of the model:

1. The entire Western Interconnect is represented, including all the loads, thermal and hydroelectric generation, and the interconnected transmission system.
2. Loads and resources are grouped according to the bulk transmission (230 KV and up) to represent known constraints and limits on electricity transfers.
3. The model uses all thermal and hydroelectric generation and transmission available at any given time to minimize market prices.
4. Generation cost supply curves are determined for each load center based on gas/coal price projections over time.
5. The model determines an efficient dispatch and import/export of generation, respecting transmission limits and wheeling rates.
6. The model can also simulate the addition of various pre-specified new generation resources in response to market prices. A new resource will be automatically added to the supply of resources when market prices are sufficient to recover the costs of that new resource, including capital recovery.

7. The market-clearing price is set by the unit on the margin for each load center and each hour. If not economic, the model will add resources to meet reserve margins.

How MIDAS Determines Prices
The model utilizes the entire bulk transmission grid to earn maximum profits for generators while at the same time minimizing market prices. Several iterations are completed as the model goes through the simulation. First, the model determines supply curves in each load center without any electricity transfers. The model will, for example, determine in iteration #1 that the supply curve where load and supply match for Wyoming is $15/MWh and where load and supply match in SP15 is $60/mwh. The model may, in iteration #2, send electricity to SP15, thereby raising the supply curve in Wyoming and lowering the supply curve in SP15.

In iteration #3, the model may decide that there are still more savings if it sends less electricity to SP15 and more electricity to COB. The model will go through several hundred iterations until market prices change by no more than a pre-specified amount, such as $0.10/MWh in our case.

When the load/supply balance becomes tight, a scarcity value is added in addition to the variable operating cost (fuel plus variable O&M). As new generation comes on-line and the reserve margin increases, the value of scarcity decreases dramatically.

A forecast for emission allowance credit costs is included in Appendix C. The assumption is that each company will be forced to comply with multi-pollutant legislation and install control equipment that will decrease the emission rate of their generators. But for the incremental cost of the next MWh, generators will need to include the cost of SO_2, NO_X, Hg and CO_2 adders in their decision to generate or not and this will add a component to market prices.

MARKETSYM

Introduction and Overview
MARKETSYM is a complete electric utility/regional pool analysis and accounting system. It is designed for performing planning and operational studies, and accommodates detailed hour-by-hour investigation of the operations of electric utilities and pools. Because it handles detailed information in a chronological fashion, planning studies performed with MARKETSYM closely reflect actual operations. MARKETSYM was the first second-generation chronological model, with new technology that vastly sped up the simulation process that used open standards for both input and reporting to link up with the latest software tools. Now, it is the first third-generation model, capable of analysis not only in the traditional cost-based world, but also in the rapidly evolving pools and free markets for power worldwide.

MARKETSYM's hourly or sub-hourly time steps can accommodate the deterministic and stochastic modeling of virtually any utility or pool situation. In the modeled time step of a study period, MARKETSYM considers a complex set of operating constraints to simulate the least-cost operation of the utility, or least-bid operation of the pool. This simulation, respecting chronological, operational, and other constraints in the case of cost-based dispatch, is the essence of the model.

The MARKETSYM stochastic module facilitates stochastic analyses. In this process an expected value trajectory for each price or physical variable and a set of stochastic model parameters are developed and entered by the user, using stochastic data input tools. During execution, Monte Carlo simulation is performed with daily random draws for average daily values for prices and loads and weekly random draws for hydro generation energy availability. Within each week, generation units are committed and dispatched as if they have perfect foresight of stochastic values for that week only.

General Capabilities of the MARKETSYM System

MARKETSYM is a general-purpose simulation model capable of representing most electric load and resource situations. To perform deterministic and/or stochastic simulations, MARKETSYM requires: at least one basic set of annual hourly loads; projections of peak loads and energies on a weekly, monthly, seasonal or annual basis for the study of any future period; and data representing the physical and economic operating characteristics of the electric utility or pool, and any relevant pool or ISO rules. The size of the system being studied, and the duration of the study, is limited only by computer capabilities and not by model restrictions. The minimum duration of simulation is one week, although a day's accumulated hourly data may be easily obtained.

PROSYM Module

The PROSYM module performs the actual simulation of utility or pool operations. PROSYM has seven modes of operation: Convergent Monte Carlo, Monte Carlo, selective Monte Carlo, antithetic sampling, probabilistic, frequency and duration of outages, and deterministic. For the purposes of this study, PacifiCorp used the Convergent Monte Carlo method for stochastic simulation.

Convergent Monte Carlo

The Convergent Monte Carlo method causes carefully distributed outages throughout each period. This is a very fast method of obtaining results of multi-iteration Monte Carlo quality. This method can reduce the standard deviation of simulation values by as much as 70 percent over true Monte Carlo. Thus, less iterations are required to produce accurate results. In many cases, a single iteration is sufficient to deliver the needed answers. Station random outages can be scheduled in a user-defined convergence period that can be a year, month or week. For the current IRP, thermal station outages in deterministic runs were modeled using derated capacity. However, the Convergent Monte Carlo outages were used in all stochastic runs.

Hourly Marginal Cost Determination

When MARKETSYM executes on an hourly basis, marginal costs are determined hourly. Marginal cost is provided for the system as a whole and for each transmission area designated as a "system area." There are three cases of marginal cost determination in MARKETSYM:

1. When resources are insufficient to meet load, the price assigned to energy not served is used for marginal cost.
2. When dump electricity is generated, the dump price is used for marginal cost. Such a situation might occur in an area when extremely high hydro runoff exceeds the native load of the transmission area.

3. When any other generating resource is the last resource dispatched to meet load in a transmission area, the incremental cost (or asking price if MARKETSYM is run in a bid based mode) of the resource over the user defined dispatch increment which spans the final generation level of the unit is used for marginal cost. If the station is in a different transmission area, the marginal cost is altered to account for any transmission losses or wheeling charges.

Transmission-Limited Area Modeling

MARKETSYM allows placing local generation requirements and transmission characteristics into sub-regions called *transmission area*s. The topology developed to represent the PacifiCorp system is comprised of 18 such transmission areas, or bubbles. The west side is comprised of six bubbles with the balance representing the east. These bubbles primarily exist to represent transmission capacities and constraints between logical geographical areas. Some of these bubbles are often referred to as *load centers*. Some of them are not load centers but contain generation resources and/or contract agreements where there is a transmission constraint to send the power to other load centers.

Each transmission area is considered attached to the main system by a transmission link. Limits and characteristics including capacity by direction, losses, and wheeling are assigned to the link. Also, a transmission area may carry its own spinning/primary reserve requirement, over and above the overall system requirement. As system commitment / dispatch proceeds, transmission areas are dealt with separately to insure the least expensive dispatch is found without violating area constraints.

When meeting load in a transmission area, the cheapest solution for the next increment of power may be within the area or outside. However, the outside increment is viewed through a "filter" of line losses and wheeling charges. For example, if the next increment of power within the area costs 15 mills, and outside, 14 mills, but wheeling charges adds 2 mills to the outside power, the cheaper solution is the 15-mill in-area power. If there are no wheeling charges but there are line losses amounting to 10 percent of power transmitted, then again, the in-area generation is more economical. However, if the transmission line is full, if there is a local generation requirement to meet, or if local spinning reserve policy requires it, the local power is used regardless of relative cost, with a corresponding effect on local marginal cost.

Another multi-area aspect to consider is that, by default, losses along transmission links are reported but not generated for. That is, if 100 MWh is needed in a neighboring transmission area, and the link from the marginal generation has a 5 percent line loss, then 100 MWh is produced in the neighboring area, 100 MWh arrives at the load, and 5 MWh is reported as lost. This is caused by the default convention that loads contain losses. The user may, however, opt to generate for line losses if not included in the load forecast.

Types of Generation Resources Modeled

MARKETSYM models a variety of generation resources and handles transactions allowing representation of all standard resource types encountered in routine production cost modeling. MARKETSYM allows you to select from six specific types of stations; all types of resources fit into one of these categories. The six station types are:

1. Thermal - Transactions/sales, generation priced at marginal cost, time-dependent units, and must-run units
2. Hydroelectric generation - Conventional Hydroelectric generation resources or any fixed energy station or contract
3. Pumped storage - Pumped-storage type resources, compressed air, exchange contracts
4. Limited energy - Limited-energy resources
5. Proxy - Stand-in "resource" representing an external event
6. Financial - Financial contracts, such as hedges, which do not involve actual electricity delivery

The specification and MARKETSYM's handling of these types of resources (or sales) are discussed in the sections below.

Thermal/Time-Dependent Generation

The default type of resource is used to represent conventional thermal units, transactions/sales, generation priced at marginal cost, time-dependent units, and must-run units.

Numerous variables are used to control the operation of a conventional thermal unit. A conventional thermal generation unit generally has a fuel cost and a heat rate. Typically, a thermal station is committed based on economics, dispatched based on economics, has a forced outage rate, a maintenance rate, and associated data to constrain operation of the unit to represent its physical characteristics. Data is entered to represent startup cost, variable O&M cost, and annual fixed cost of the station. Emissions data may be input for any unit that is thermal. The data specifies pounds (or kg) of a particular emission/million Btu (or GJ) of fuel consumed by the unit, pounds (or kg)/MWh produced by the unit, pounds (or kg)/hour of operation of the unit, or (in the case of NO_X) a point-by-point, third-order, or exponential equation based on electricity output.

A transaction is also modeled as a station resource. In the case of a sale, its maximum capacity is given by a negative number, and its optional minimum capacity is either a negative number or zero. If the commit variable indicates that the transaction is must-run, it must be scheduled, but MARKETSYM chooses any level of transaction between the minimum and maximum levels, depending on economics. If it is an economic transaction, the model may choose not to sell electricity in hours when revenues do not contribute above cost, or not to buy electricity when it costs more than the generating cost. The commit variable is used to force the transaction, or allow commitment at the model's discretion.

The following information about a station is input on a generating unit basis:

1. Maximum capacity of each unit
2. Minimum capacity of each unit
3. Dependable per-unit capacity
4. Peaking capacity, for use under specified conditions
5. Actual pre-specified commitment and/or unit dispatch
6. Daily charge for operating a unit for at least one hour in the day
7. Variable O&M cost of each unit
8. The heat rate curve for a unit

9. Pre-scheduled maintenance, number of units and duration
10. Maintenance rate, for distributed maintenance/unit
11. Mean, maximum, and minimum time to repair, for outages scheduled by Convergent Monte Carlo
12. Minimum up and down times of a unit
13. Per-hour operating cost, exclusive of fuel and variable O&M cost
14. Pumped storage pumping capacity, and pumping minimum
15. Unit ramp and run-up rates
16. Unit startup O&M and fuel cost and corresponding hours

Run-of-River and Storage Hydroelectric generation/Fixed Energy
Like the thermal stations described above, these stations have a maximum and minimum generating capacity, but they also have a fixed amount of energy they must use within a specified time (a week or a month). Hydro stations can be directed to operate in a manner to level the load shape served by other stations or to dispatch based on expected market price. Hydro stations are scheduled one at a time over the horizon of the week, subject to hourly constraints for minimum and maximum generation, and weekly constraints for ramp rates, and total energy. The load shape they intend to level can be set to the transmission area, control area, or overall system load.

In a peak shaving mode, the mode used by PacifiCorp, a hydroelectric station is first scheduled to operate at its minimum for all hours and the load for each hour is reduced by the amount of this generation. If this schedule is less than the week's energy, the generation is increased by an increment (for the hours with the highest adjusted loads; the loads for these hours are accordingly adjusted downward). Hourly constraints are enforced during the dispatch process. This process is continued until the total weekly generation for this station matches the specified value. Interpolation is used on the last increment.

Fixed Energy Transactions
Fixed energy transactions are a special case of hydro, and are treated similarly. MARKETSYM allows four fixed energy transactions: peak-shave purchase, peak-build sale, valley-take purchase, and valley-fill sale. Which transaction type is appropriate depends on whether the purchaser or the seller controls the rate and time of power delivery.

Pumped Storage Plants/Energy Exchange Contracts/CAES Units
MARKETSYM makes use of a value-of-energy method of dispatch. This method allows accurate results, flexibility in modeling generation/pay back resources other than pumped storage plants, and accounting for head variations in pumped storage plants. The method also provides a meaningful measure of marginal cost when a pumped storage plant is the marginal plant. The water (fuel) of pumped hydro generation is valued at the cost of pumping, allowing for net plant efficiency. Hourly reservoir levels are computed and a look-ahead is employed to prevent drawing the reservoir below the level where pumping space allows refilling to the desired level before the beginning of the next peak period.

Energy-Limited Generating Units
MARKETSYM allows modeling of resources that have maximum and/or minimum energy limits. These are specified energy limited in the station's description.

Unit Commitment Logic in MARKETSYM

This section briefly describes the unit commitment and dispatch logic and associated features in MARKETSYM. This is followed by descriptions of the separately licensed add-on MARKETSYM modules and their interaction with unit commitment.

MARKETSYM's unit commitment and dispatch logic is designed to mimic "real world" electricity system hourly operation. This involves:

1. Minimizing system production cost
2. Enforcing the constraints specified for the system, stations, associated transmission, fuel, and so on

Depending upon whether MARKETSYM is directed to dispatch on a cost-based or bid-based manner, the minimization of the system "production cost" is based on station production cost or the station bidding prices. The following criteria are observed during the commitment process.

1. **System and local security**. MARKETSYM allows the user to specify three levels of spinning and primary reserve: system level, control area level, and transmission area level. The user can specify the reserve at any level or at all the levels. The unit commitment and dispatch logic not only looks in the current hour but also looks into the future hours for the possible security violation. If the de-commitment of a station will cause a reserve violation in the current hour or future hours, the station will remain on-line.
2. **Station physical constraints**. The user can specify minimum up and down time for each station.
   - If a station was off-line in the previous hour, the logic counts the number of hours the station has been off-line and compares the number with the station's minimum down time.
   - If the number of off-line hours is less than the minimum down time, the station will remain off-line in the current hour.
   - If the station can be de-committed, MARKETSYM's "look-ahead" logic estimates how many hours the station can be off-line. If the number of possible off-line hours is less than the minimum down time, the station will be kept on-line.
   - By the same token, the station minimum up time criterion is checked if the station was on line in the previous hour. Also, the ramp rate and run up rate is considered in the de-commitment decision process. If a station with ramp rate or run up rate will be needed in a given hour, the station will be committed a few hours earlier for ramping up. Similarly, if a station is about to be de-committed, the station will ramp down and prepare to be shut down.
3. **Transmission Constraints**. MARKETSYM determines power flow to equalize the incremental costs of all transmission areas in the system and enforce the power flow constraints. A transmission area may import inexpensive power from its neighbors or export power to replace its neighbor's expensive power. A station may pass the other criterion tests, but if, for example, the inexpensive replacement of energy cannot reach the transmission area the station is located in, the station will not be de-committed.
4. **Limited Fuel Constraints.** The MARKETSYM limited fuel logic interactively works with the unit commitment and dispatch logic to observe fuel limits while economically

dispatching stations. A station may be kept on-line to avoid fuel under-burn, or off-line to avoid fuel over-burn. The fuel consumption status is passed back to the commitment and dispatch logic by station shadow prices. If a fuel is over-burnt, the shadow price of the stations burning this fuel will be the "emergency" price. If a fuel is under-burnt, the shadow price of the stations burning the fuel will be the "dump power" price.

5. **Other operations constraints**. The other operation constraints include Heat Production Constraints, Transmission Area minimum generation constraints, etc. The constraints are enforced in two ways: keep stations on-line or off-line or at certain generation level to meet the constraints or the constraints are quantified by shadow prices added to the commitment and dispatch prices.
6. **Economy.** The MARKETSYM look ahead logic can estimate how may hours that a station can be off-line in the future. The cost of the station minimum capacity in the off-line hours is compared with the startup and stop cost. A de-commitment decision is made if the startup and stop cost is less than the cost of the station minimum capacity less the replacement cost.

CAPACITY EXPANSION MODEL (CEM)

PacifiCorp has acquired from Global Energy Services a new Capacity Expansion Model (CEM) for automated screening and evaluation of generation capacity expansion and retirement options. The CEM is an economic optimization model and was used by PacifiCorp in the preparation of its 2004 Integrated Resource Plan.

The CEM helps formulate the key investment decisions of (1) what to build, (2) where to build, (3) how much to build, and (4) when to build. It also answers the question of what to retire. The result is a least-cost portfolio that respects all of the operational constraints in the model. This portfolio can then be simulated using the detailed hourly dispatch model, MARKETSYM.

In the 2004 IRP, the CEM was used to augment the manual portfolio development procedures that were used in prior years. Numerous portfolios were developed using the manual build tables described in Chapter 5. Also, an additional portfolio was developed with the CEM. All of these portfolios were then simulated and analyzed with MARKETSYM.

Model Description

The CEM is a mixed integer programming (MIP) model that schedules new resource additions and existing resource retirements to minimize total costs over the IRP planning horizon. It is developed in the GAMS (General Algebraic Modeling System) development language by the GAMS Development Corporation and is solved using the CPlex optimizer by ILOG Corporation.

For a 20 year study period, the model assumes a two-bubble topology for representing the west and east control areas separately. In addition, the CEM models the transmission capacity constraints between each control area for each direction of energy flow. This allows the modeling of such issues as increased transfer capability between areas.

Model Scope

The CEM has the following model scope and characteristics:

1. The CEM performs a deterministic evaluation of the optimal resource plan (expansion and retirement) for the company generation portfolio. The objective function is to minimize the net present value cost of generation, construction, and expansion subject to load balance constraints, reliability constraints, and capacity constraints.

2. The study period is 20 years.

3. The CEM allows the portfolio positions (generators, loads, DSM activities, and contracts) to be contained in up to two distinct geographical areas (control areas, east and west).

4. Each control area has access to an external market to buy and sell power. These markets generally affect the hourly dispatch, but can influence the build decision for new resources.

5. The CEM models PacifiCorp's transmission rights between the east and west. Transmission capacity is modeled with the same granularity as dispatch and can be different for each direction of energy flow. Portfolio options may include increasing transfer capability between the two areas. Improved transmission capability within an area that results in access to more or lower priced resources may also be modeled through added capital costs.

6. The user has the ability to define the set of resource options, which includes the following types of investments:
   a. Supply resource additions
   b. Supply resource retirements
   c. Demand side options

7. The CEM recommends the potential optimal resource plan, considering the cost effectiveness of the resource options, including their scale and timing. Decisions on portfolio additions or retirements are made on an annual basis.

8. The model creates an hourly or aggregated time-of-day least cost dispatch of all existing resources and installed proposed resources considering those resources' heat rate, fuel cost, location, capacity, emissions cost, and variable O&M. The hourly dispatch also includes optimal flows between control areas considering the tie line capacities and line losses.

9. To speed solution time, it is necessary to limit the number of time periods that are represented. For example, it is difficult to model every hour of a 20-year study period. The CEM thus makes use of representative or aggregate hours, which to an extent can be user-specified. The user can choose the number of hours with the understanding that a higher number will increase model solution time. Typically, initial runs for rough screening can use fewer hours while final runs may be subject to finer granularity. The user can specify the following three levels of granularity, with Level 1 having the lowest level of precision and fastest solution time and Level 3 having the highest precision and slowest solve time. These three levels are the following:

   a. 12 months/year x 1 week/month x 3 days/week x 6 hours/day = 216 hours/year
   b. 12 months/year x 1 week/month x 7 days/week x 6 hours/day = 504 hours/year

c. 12 months/year x 1 week/month x 7 days/week x 24 hours/day = 2,016 hours/year

10. The CEM has the ability to model the planned and forced outages of the existing and expanded capacity of the portfolio. The forced outages are modeled by de-rating the capacity of each plant. These de-rates may vary by year for each resource. Also, the model takes scheduled maintenance outages and computes planned outage rates that vary by year and season for each resource.

11. The model requires that sufficient capacity be installed to meet seasonal peak loads plus a planning reserve margin.

12. The model enforces monthly energy limits on hydro and energy limited resources.

13. An exogenous energy market is available in each control area for the model to make "spot" purchases and sales. This market is reflected by a piece-wise linear price curve. The price points are aggregated in the same time step as the simulation. (See issue 9 above). Capacity markets are not modeled.

14. The model accommodates approximately 100 existing resources and 30 proposed resources. The model solution time decreases with a smaller set of decision variables. Thus, managing the number of potential new resources or transmission options could largely control run time. The PacifiCorp system as represented in MARKETSYM currently has over 90 individual contracts, all but two of which are must run with set delivery schedules. This number of contracts was reduced through aggregation of similar contracts. Similar thermal units at same-site stations are also aggregated (such as Hunter 1-3). The 20 or so hydro units were reduced in aggregation by type and location (peaking versus run-of-river, and east versus west).

15. Capital recovery factors (CRF) eliminate the need for residual value accounting as the recovery factor shall be used to calculate the cash flow to the end of the resources' expected life.

    The CRF is defined as:

    CRF = i / (1-(1+i)^-n)

    It's also commonly expressed as:

    CRF = i(1 + i)n / {(1 + i)n - 1}

    Where

    i = interest rate

    n = lifetime of investment

    For example, when i = 0.10 and n = 10, the capital recovery factor CRF = 0.163. The CRF is used to calculate annual levelized capital recovery cost, accounting for depreciation and return on capital. If you amortize over the useful life, the Capacity Expansion Model need not include salvage value. It will simply be computed as the remaining book value after m years of life. The CRF is applied over the first n years of the study. For simple capital budgeting, annualized costs can include other factors that are proportional to capital cost, for property taxes, insurance, and overhead.

16. Hydro and limited energy stations are modeled with a reservoir constraint that requires that the sum of the energy produced in a given time period be less than some MWh value. This value may be specified monthly.

17. To guarantee the convergence of the LP solution, the following assumptions are applied to the implementation of the capacity expansion algorithm:

    a. Ramp rates, minimum up/down times, and run up rates are not enforced
    b. Expected values for inputs such as load, fuel prices, hydro availability are used (i.e. the model is deterministic, not stochastic)
    c. The CEM is not a unit commitment model, and as such, start costs are included in variable operating costs by making assumptions on the number of starts per week for each unit or technology type

Model Objective and Constraints

The CEM has the objective function of minimizing the net present value (NPV) of portfolio operating cost (fuel, fixed and variable maintenance, un-served energy, and un-served reserves) plus the cost of generation and transmission capacity expansion of the system over the entire study period.

The model has both short and long-term objectives. In the short run, the model minimizes existing thermal and hydro dispatch costs subject to system and unit constraints. In the long run, the model determines an optimal system-wide development plan given a set of supply and demand side resources.

The CEM allows the user to impose a set of resource planning constraints within the following classes of linear inequality constraints:

Constraints

1. **Energy balance constraints.** These perform the hourly dispatch of resources to satisfy demand as well as do market purchases and sales

2. **Planning margin constraints**. These build resources to ensure that the target planning margin is met while not going over the upper limit on planning margin

3. **Generation constraints**. These enforce lower and upper limits on generation in each time period for each resource

4. **Must run constraints**. These ensure that must run resources are always run in the dispatch

5. **Limited energy constraints**. These enforce monthly energy limits on hydro and energy limited resources

6. **Site build constraints**. These allow a number of units to be built on a given site

7. **Duct firing unit constraints**. These ensure that duct firing units are built in the same year as the corresponding combined-cycle unit

8. **Group capacity mix constraints**. These ensure that resource groups are built according to a desired percentage distribution

9. **Group capacity level constraints**. These ensure that resource groups are built according to user defined MW limits

10. **Aggregate capacity expansion constraints**. These allow the user to specify minimum and maximum MW capacity to build by year

11. **Capital budget constraints**. Allows the user to limit capital expenditure in a given year across all investments to a specified amount

Variables

The Capacity Expansion Model optimizes the following groups of variables:

1. **Energy dispatch variables**. By time period and resource, these determine optimum dispatch levels

2. **Firm capacity variables**. By month and resource, these add proposed resources to respect the planning margin limits

3. **Firm capacity transfers**. These allow the transfer of firm capacity between the east and west for use in planning margin constraints

4. **Energy transfers**. These allow the transfer of dispatched energy between the east and west

5. **Un-served energy variables**. These indicate un-served when the energy balance constraints cannot meet load

6. **Un-met capacity variables**. These indicate un-met capacity when the planning margin constraints cannot meet peak loads

7. **Market purchases**. These allow the model to purchase from market to augment dispatch to meet hourly load

8. **Market sales**. These allow the model to sell to market after hourly load has been met

9. **Site-build variables**. These 0/1 integer variables allow the model to build or not build a given resource site in a given year

10. **Unit-build variables**. These integer variables allow the model to add units to a site up to the maximum number of units per site

CONCLUSIONS

PacifiCorp uses three main models in the formulation of the IRP. These are the MIDAS Gold Transact Analyst for deriving forward market prices, the MARKETSYM least-cost dispatch model and the new Capacity Expansion Model for performing automated capacity expansions and developing initial portfolios. These three models are owned and supported by Global Energy Services based in Boulder, Colorado. These systems comprise the core of modeling tools used by PacifiCorp for developing its biennial Integrated Resource Plan.

APPENDIX I – RETAIL LOAD FORECASTING

INTRODUCTION - METHODOLOGY

PacifiCorp estimates total load by starting with customer class sales forecasts in each state and then adds line losses to the customer class forecasts to determine the total load required at the generators to meet customer demands. PacifiCorp uses different approaches in forecasting sales for different customer classes. PacifiCorp also employs different methods to forecast the growth over different forecast horizons. Near term forecasts rely on statistical time series and regression methodologies while longer term forecasts are dependent on end-use and econometric modeling techniques. These models are driven by county and state level forecasts of employment and income that are provided by public agencies or purchased from commercial econometric forecasting services.[22]

NEAR TERM CUSTOMER CLASS SALES FORECAST METHODS

Residential, Commercial, Public Street and Highway Lighting, and Irrigation Customers

Sales to residential, commercial, public street and highway lighting, and irrigation customers are developed by forecasting both the number of customers and the use per customer in each class. The forecast of kWh sales for each customer class is the product of two separate forecasts: number of customers and use per customer.

The forecast of the number of customers relies on weighted exponential smoothing statistical techniques formulated on a twelve-month moving average of the historical number of customers. For each customer class the dependent variable is the twelve-month moving average of customers. The exponential smoothing equation for each case is in the following form:

$$S_t = w*x_t + (1\text{-}w) * S_{t-1}$$

$$S_t^{(2)} = S_t *x_t + (1\text{-}w) * S_{t-1}^{(2)}$$

$$S_t^{(3)} = S_t^{(2)} *x_t + (1\text{-}w) * S_{t-1}^{(3)}$$

where x_t is the twelve-month moving average of customers. The form of this forecasting equation is known as a triple-exponential smoothing forecast model and, as derived from these equations, most of the weight (w) is applied to the more recent historical observations. By applying additional weight to more current data and utilizing exponential smoothing, the transition from actual data to forecast periods is as smooth as possible since a "smoothed" forecast, S_t, is produced. This technique also ensures that the December to January change from year to year is reflective of the same linear pattern. These forecasts are produced at the class level for each of the states in which PacifiCorp has retail service territory. PacifiCorp believes that the recent past is most reflective of the near future. Using weights applies greater

[22] PacifiCorp relies on county and state-level economic and demographic forecasts provided by Global Insight, in addition to state office of planning and budgeting sources.

importance to the recent historical periods than the more distant historical periods and improves the reliability of the final forecast.

The average use per customer for these classes is calculated using regression analysis on the historical average use per customer, which determines if there is any material change in the trend over time. The regression equation is of the form

$KPC_t = a + b*t$

where KPC is the annual kilowatt-hours per customer and "t" is a time trend variable having a value of zero in 1992 with increasing increments of one thereafter. "a" and "b" are the estimated intercept and slope coefficients, respectively, for the particular customer class. As in the forecast of number of customers, the forecasts of kilowatt-hours per customer are reviewed for reasonableness and adjusted if needed. The forecast of the number of customers is multiplied by the forecast of the average use per customer to produce annual forecasts of energy sales for each of the four classes of service.

Industrial Sales and Other Sales to Public Authorities

These classes are diverse. In the industrial class, there is no typical customer. Large customers have differing usage patterns and sizes. It is not unusual for the entire class to be strongly influenced by the behavior of one customer or a small group of customers. In order to forecast customer loads for industrial and other sales to public authorities, these customers are first classified based on their Standard Industrial Classification (SIC) codes, numerical codes that represent different types of businesses. Customers are further separated into large electricity users and smaller electricity users. PacifiCorp's forecasting staff, which consults with each PacifiCorp customer account manager assigned to each of the large electricity users, makes estimates of that customer's projected energy consumption. The account managers maintain direct contact with the large customers and are therefore in the best position to know whether any plans or changes in their business processes may impact their energy consumption. In addition, the forecasting staff reviews industry trends and monitors the activities of the customers in SIC code groupings that account for the bulk of the industry sales. The forecasting staff then develops sales forecasts for each SIC code group and aggregates them to produce a forecast for each class.

LONG TERM CUSTOMER CLASS SALES FORECAST METHODS

Economic and demographic assumptions are key factors influencing the forecasts of electricity sales. Absent other changes, demand for electricity will parallel other regional and national economic activities. However, several influences can change that parallel relationship, for example changes in the price of electricity, the price and availability of competing fuels, changes in the composition of economic activity, the level of conservation, and the replacement rates for buildings and energy-using appliances. The long term forecast considers all of these as variables. The following is a generalized discussion of the methodology implemented for the long term forecast. The forecast is derived from a consistent set of economic, demographic and price projections specific to each state served by PacifiCorp. These states are California, Idaho, Oregon, Utah, Washington and Wyoming. Forecasts of employment, population and income with a consistent view of the western half of the United States are used as inputs to the forecasting models.

Economic and Demographic Sector

Employment serves as the major determinant of future trends among the economic and demographic variables used to "drive" the long-term sales forecasting equations. PacifiCorp's methodology assumes that the local economy is comprised of two distinct sectors, "basic" and "non-basic," as presented in regional export base theory.[23]

The basic sector is comprised of those industries that are involved in the production of goods destined for sales outside the local area and whose market demand is primarily determined at the national level. PacifiCorp calculates its regional share of the employment for these specific industries based on national forecasts of employment for the industries.

The non-basic sector theoretically represents those businesses whose output serves the local market and whose market demand is determined by the basic employment and output in the local economy.

This simplistic definition of industries as basic or non-basic does not directly confront the problem that much commercial employment (traditionally treated as non-basic) has assumed a more basic nature. This problem is overcome by including other appropriate additional national variables, such as real gross national product in the modeling. In addition, forecasts for county and state populations are also employed as forecast drivers. From these, service territory level population forecasts are developed and used.

Two primary measures of income are used in producing the forecast of total electricity sales. Total personal income is used as a measure of "economic vitality" which impacts energy utilization in the commercial sector. Real per capita income is used as a measure of "purchasing power" which impacts energy choice in the residential sector. PacifiCorp's forecasting system projects total personal income on a service territory basis.

PacifiCorp has found that the price of electricity has little influence on the use of electricity. PacifiCorp evaluated the price elasticity on residential consumption using econometric analysis. The study found that for six models the price elasticity of demand was less than 0.10 (in absolute value) which is considered to be in the inelastic range of values. Thus, it can be concluded that currently price has minimal effect on the consumption of electricity.

A complementary study was performed evaluating the change in residential customer usage during the summer in response to higher bills. The study concluded that customers were willing to pay a substantial premium for air conditioning. Based on this analysis and the price inelasticity of demand, the highest "block" of an inverted block design would have to be substantially higher than the other blocks in order to have an effect on customer usage. The inverted block design was filed during February 2004 and was implemented during April 2004.

[23] The regional export base theory contends that regional economies are dependent on industries that export outside of the region. These industries, and the ones that support them, are the industries that are the major job creators of the region.

As a result there are too few observations to measure the price impact of the inverted block design. PacifiCorp will continue to monitor the price influence on the load forecast of a tiered rate design as more historical observations of usage and prices with the tiered rate design occur.[24]

Residential Sector

PacifiCorp's residential end-use forecasting model has been developed to forecast specific uses of electricity in the customer's home. It is a hybrid econometric-end use model. The model explicitly considers factors such as persons per household, fuel prices, per capita income, housing structure types, and other variables that influence residential customer demand for electricity. Residential demand is projected on the basis of 14 end-uses. These uses are space heating, water heating, electric ranges, dishwashers, electric dryers, refrigerators, lighting, air conditioning, freezers, water beds, electric clothes washers, hot tubs, well pumps and residual uses. Air conditioning can be either central, window or evaporative (swamp coolers).

For each end use and structure type, PacifiCorp looks first at saturation levels (the number of customers equipped for that end use) and how they may change in response to demographic and economic changes. PacifiCorp then looks at penetration levels, (how many households are expected to adopt that end-use in the future), given the economic and demographic assumptions. Penetration and saturation rates in the space heating, water heating, cooking, and clothes drying end uses considers the choice of electric appliances compared against the choice of some alternative energy source, (e.g., natural gas or oil). In addition, the number of houses that currently have the end use will be removed upon demolition of the structure. Some appliances may be replaced several times before a home is removed. The life expectancy of various appliances compared to the life expectancy of a home is considered in the forecasting process. It is also possible that for a particular appliance more than one exists within a household. For certain appliances, e.g., air conditioning, the saturation rate has been adjusted to account for this occurrence. For other appliances, (e.g., lighting), the saturation rate is assumed to be one and the usage per appliance for the average household is adjusted to account for more than one light fixture in the house. In this case the average usage per appliance represents the lighting electrical usage in the average household.

The basic structure of the end-use model is to multiply the forecast appliance saturation by the appropriate housing stock, which is then multiplied by the annual average electricity use per appliance.

$$\text{Consumption} = \text{Housing stock}_{k} * \text{saturation of appliance}_{ik} * \text{electricity usage of appliance}_{ik}$$

where: i= appliance type
k=housing type

Annual average electricity use per appliance for each structure type is either estimated by using a conditional demand analysis or it is based upon generally accepted institutional, industry and engineering standards.

[24] The results of the study were presented during the Load Forecasting Technical Workshop of June 25, 2004.

PacifiCorp models three structure types within two age categories, new and existing, because consumption patterns vary with dwelling type as well as age. Therefore new and existing homes are separated into single family, multi-family and mobile home dwelling types.

These models allow PacifiCorp to calculate the number of residential customers within each of the new and existing customer categories. These customers are then distributed between the various structure types and sizes. End uses are forecasted for each structure and customer category and these are multiplied by the annual consumption level for each end use. Summing the results gives the total residential sales.

Commercial Sector

The commercial model is a hybrid econometric-end-use model like the residential model. It forecasts electricity in the same fashion but uses energy use per square foot for seven end uses among 12 commercial activities or vertical market segments (VMS).

$$\text{Consumption} = \text{Square foot}_{k}, * \text{saturation of appliance}_{ik} * \text{electricity usage of appliance}_{ik}$$

where: i= appliance type
k=commercial activity type

The seven end-uses are space heating, water heating, space cooling, ventilation, refrigeration, lighting and miscellaneous uses. Penetration and saturation rates in the space heating and water heating end uses considers the choice of electric appliances compared against the choice of some alternative energy, e.g., natural gas or oil.

Twelve vertical market segments (building types or commercial activities) are modeled: communications/utilities/transportation, food stores, retail stores, restaurants, wholesale trade, lodging, schools, hospitals, other health services, offices, services, and a miscellaneous category. The 12 VMS are defined based upon Standard Industrial Classifications (SIC). Individual forecasts for each market segment are totaled for an overall commercial sector forecast.

Industrial Sector

PacifiCorp's industrial sector is somewhat dominated by a small number of firms or industries. The heterogeneous mix of customers and industries, combined with their widely divergent characteristics of electricity consumption indicates that a substantial amount of disaggregation is required when developing a proper forecasting model for this sector. Accordingly, the industrial sector has been heavily disaggregated within the manufacturing and mining customer segments.

The manufacturing sector is broken down into nine categories based on the Standard Industrial Classification Code System, these are: food processing (SIC 20), lumber and wood products (SIC 24), paper and allied products (SIC 26), chemicals and allied products (SIC 28), petroleum refining (SIC 29), stone, clay and glass (SIC 32), primary metals (SIC 33), electrical machinery (SIC 36) and transportation equipment (SIC 37). A residual manufacturing category, composed of all remaining manufacturing SIC codes, is also forecasted.

The mining industry, located primarily in Wyoming and Utah, has been disaggregated into at least four categories. Separate forecasts are performed for the following industries: metal mining

(SIC 10), coal mining (SIC 12), oil and natural gas exploration, pumping and transportation (SIC 13), non-metallic mineral mining (SIC 14); there also exists an "other" mining category in some states.

The industrial sector is modeled using an econometric forecasting system. The independent variables for these equations are the industrial production indexes for the specific industry and the relative prices of electricity and natural gas. This relative price variable captures the use of alternative energy sources.

Other Sales

The other sectors to which electricity sales are made are irrigation, street and highway lighting, interdepartmental and "other sales to public authorities."

Electricity sales to these smaller customer categories are either forecasted using econometric equations or are held constant at their historic sales levels.

Merging of the Near Term and Long Term Sales Forecasts

The near term forecast has a horizon of at most three years while the long term forecast has a horizon of approximately twenty years. Each forecast uses different methodologies, which model the influential conditions for that time horizon. When the forecast of usage for a customer class differs between the near term and the long term, judgments and mathematical techniques are implemented in the last year of the near term forecast thereby converging these values to the long term forecast.

TOTAL LOAD FORECAST METHODS

System Load Forecasts

The sales forecasts by customer class previously discussed measure sales at the customer meter. In order to measure the total projected load that PacifiCorp is obligated to serve line losses must be added to the sales forecast. The state sales forecasts are increased by the estimates for system line losses. Line loss percentages vary by type of service and represent the additional electricity requirements to move the electricity from the generating plant to each end-use customer. This increase thereby creates the total system load forecast on an annual basis. This annual forecast is further distributed to an hourly load forecast so that the peak hour demand forecast is obtained.

Hourly Load Forecasts

To distribute the loads across time PacifiCorp has developed a regression based tool that models historical hourly load against several independent variables at the state level. These models have a large number of independent variables. Many of these represent spatial conditions over the year, such as the time of day, the week of the year or day of the week. Additionally hourly temperature for weather stations where the bulk of the load in the state resides is used in the model. A variable representing the humidity levels in the state is also used.

Forecasts of the many independent variables are used with these models to create forecasts of hourly loads relative to the many different factors. For the spatial variables the date and time in the future is used. Typically the load on a weekend is lower than on a weekday because the industrial and some commercial customers use less. So a variable used to identify a weekend would have a lower contribution to the forecasted load than a weekday and just using the calendar date in future identifies these spatial conditions. For the weather values the models use the equivalent of the 30-year average temperature for the weather stations at the appropriate day and time in the future. This is also what is used for the humidity measure.

A review of the forecasted growth of the hourly load over time against historical growth rates is done to make sure that the loads are growing at the appropriate times. State loads are aggregated by month by time of day and future growth rates are compared with historical growth rates. This allows us to review the night time growth rates verses daytime growth rates. Growth in the winter months may differ from the growth in the spring and fall. All of this is reviewed and trends are incorporated to reflect the historical patterns observed. Hourly loads are then summed across the months of the forecast period to develop monthly loads. This is done because this process incorporates expected weather conditions into the appropriate month based on normal weather patterns.

System Peak Forecasts

The system peaks are the maximum load required on the system in any hourly period. Forecasts of the system peak for each month are prepared based on the load forecast produced using the methodologies described above. From these hourly forecasted values, forecast peaks for the maximum usage on the entire system during each month (the coincidental system peak) and the maximum usage within each state during each month are extracted.

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 233 MWa of Class 2 programs in the forecast. This savings includes 86 MWa to be implemented by the Energy Trust of Oregon within PacifiCorp's service territory. Table I.1 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 I.1 – Class 2 DSM Included in the System Load Forecast

MWa	FY 06	FY 07	FY 08	FY 09	FY 10	FY 11	FY 12	FY 13	FY 14	FY 15
PacifiCorp	29	47	65	81	95	108	122	135	147	147
Energy Trust of Oregon	21	32	42	52	63	74	84	86	86	86
TOTAL (MWa)	**50**	**79**	**107**	**133**	**158**	**182**	**206**	**221**	**233**	**233**
Peak Reduction (MW)	**58**	**99**	**138**	**176**	**210**	**240**	**269**	**300**	**322**	**323**

Summary of System Net Control Area Load Forecast

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.1% annually from fiscal year 2006 to 2015. This is slightly faster than the average annual historical growth rate experienced from fiscal year 1991 to fiscal year 2003. During this historical period the total load for these states increased at an average annual rate of 1.6%. Table I.2 shows the historical load and Table I.3 shows the forecasted load for each specific year for each state served by PacifiCorp and the average annual growth (AAG) rate over the entire time period.

Table I.2 – Historical Net Control Area Load Growth (MWh)

Fiscal year	Total	OR	WA	WY	CA	UT	ID
1991	42,663,126	13,532,508	3,767,092	9,481,882	867,538	12,775,356	2,238,749
1992	44,825,116	13,618,057	3,777,960	9,373,550	863,355	14,074,702	3,117,493
1993	46,761,134	14,124,120	4,102,276	9,494,455	856,386	14,991,579	3,192,317
1994	46,975,155	14,548,674	3,986,609	9,529,295	880,864	15,001,864	3,027,849
1995	50,004,592	14,926,381	4,175,894	9,297,920	977,027	17,326,310	3,301,059
1996	48,015,571	14,448,571	4,185,264	8,696,345	899,011	16,630,744	3,155,635
1997	49,678,279	14,892,974	4,280,797	8,418,347	922,714	17,787,304	3,376,143
1998	49,148,106	14,964,493	4,066,850	7,619,244	960,505	18,247,264	3,289,750
1999	50,567,430	15,492,969	4,480,478	7,734,681	991,955	18,558,538	3,308,810
2000	51,121,333	15,346,055	4,638,472	7,350,834	1,142,356	19,358,678	3,284,938
2001	52,796,537	15,501,772	4,523,313	7,895,089	893,178	20,521,909	3,461,275
2002	51,993,876	14,786,652	4,418,555	8,191,464	877,456	20,267,966	3,451,783
2003	51,578,906	14,190,829	4,377,938	8,230,153	905,192	20,355,238	3,519,555
AAG	1.59%	0.40%	1.26%	-1.17%	0.35%	3.96%	3.84%

Table I.3 – Forecasted Net Control Area Load Growth (MWh)

Fiscal year	Total	OR	WA	WY	CA	UT	ID
2006	56,185,236	15,445,123	4,686,144	8,001,255	952,600	23,540,523	3,559,591
2007	56,701,012	15,375,150	4,574,199	7,904,230	995,141	24,385,958	3,466,333
2008	58,090,112	15,568,513	4,631,668	7,996,010	1,007,571	25,390,832	3,495,518
2009	59,221,010	15,683,985	4,662,537	8,114,524	1,014,840	26,233,491	3,511,632
2010	60,587,471	15,882,775	4,731,506	8,192,539	1,029,615	27,197,650	3,553,385
2011	61,749,220	16,061,304	4,797,797	8,118,744	1,041,480	28,144,063	3,585,833
2012	63,411,750	16,280,684	4,902,646	8,310,190	1,061,585	29,201,060	3,655,586
2013	64,494,595	16,405,779	4,940,987	8,404,568	1,067,681	30,011,107	3,664,473
2014	66,039,301	16,691,370	5,025,475	8,565,776	1,082,497	30,968,624	3,705,558
2015	67,577,097	16,962,396	5,116,167	8,664,663	1,099,041	31,980,956	3,753,873
AAG	2.07%	1.05%	0.98%	0.89%	1.60%	3.46%	0.59%

As can be seen from the average annual growth rates at the bottom of the Table I.2 the eastern system continues to grow faster than the western system, with an average annual growth rate 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 Western Wyoming. There are many natural gas fields in Western Wyoming served by PacifiCorp. These fields are expected to deplete in the coming years and cease operations. In the base case this occurs after approximately 30 years of gas extraction.

The system peak load is expected to grow at a faster rate than the overall load due to the changing mix of appliances over time. Table I.4 shows the historical total peak for fiscal year 1991 through fiscal year 2003. Table I.5 below shows that for fiscal year 2006 through fiscal year 2015 the total peak is projected to grow by 3.0%. Until recently the system peak occurred in the winter months. Due to changing appliance mix from an increasing demand for summer space conditioning in the residential and commercial classes and a reduction in electric related space conditioning in winter months it has started occurring in summer months. We expect this condition to continue. Therefore the increasing summer load and decreasing winter loads are expected to result in a faster growing system peak than total load until changes in space conditioning equipment ends.

Table I.4 – Historical Coincident Net Control Area Peak Load (MW)

Fiscal year	Total	OR	WA	WY	CA	UT	ID
1991	7,377	3,003	798	1,299	206	1,823	248
1992	6,776	2,422	676	1,198	165	1,929	395
1993	7,208	2,582	799	1,239	150	2,087	352
1994	7,364	2,750	783	1,244	174	2,033	380
1995	7,283	2,679	742	1,159	169	2,202	331
1996	7,816	2,742	930	1,221	164	2,344	414
1997	7,632	2,774	798	989	174	2,483	415
1998	7,413	2,457	780	1,025	136	2,652	363
1999	8,354	2,900	810	1,046	190	2,968	440
2000	7,972	2,208	791	892	214	3,170	697
2001	8,480	2,347	756	979	154	3,721	523
2002	7,899	2,122	627	1,091	124	3,514	421
2003	8,597	2,192	756	1,041	161	3,758	689
AAG	1.28%	-2.59%	-0.46%	-1.83%	-2.03%	6.21%	8.88%

Table I.5 – Forecasted Coincident Net Control Area Peak Load (MW)

Fiscal year	Total	OR	WA	WY	CA	UT	ID
2006	8,624	2,101	781	992	148	4,121	480
2007	8,870	2,088	767	946	157	4,343	568
2008	9,145	2,113	786	960	156	4,600	531
2009	9,446	2,150	797	971	162	4,794	572
2010	9,749	2,185	814	992	165	5,019	575
2011	10,005	2,199	838	972	169	5,254	573
2012	10,301	2,229	856	991	173	5,475	578
2013	10,565	2,248	877	1,009	171	5,718	542
2014	10,896	2,286	895	1,022	179	5,932	582

Fiscal year	Total	OR	WA	WY	CA	UT	ID
2015	11,248	2,352	917	1,043	182	6,165	588
AAG	3.00%	1.26%	1.80%	0.56%	2.35%	4.58%	2.28%

Table I.6 shows the historical non-coincidental total peak demands for each of the states for fiscal year 1991 through fiscal year 2003. The AAG is shown at the bottom of the table for each state. A total system peak demand is not given since the individual state peak demands occur at different months and hours for the fiscal year.

Table I.6 – Historical Non-Coincident Net Control Area Peak Load (MW)

Fiscal year	OR	WA	WY	CA	UT	ID
1991	3,003	811	1,382	206	2,092	477
1992	2,422	697	1,279	165	2,325	643
1993	2,640	808	1,300	166	2,445	604
1994	2,750	783	1,332	174	2,343	635
1995	2,680	783	1,253	181	2,636	675
1996	2,748	930	1,237	178	2,689	625
1997	2,774	817	1,242	181	2,929	692
1998	2,482	801	1,095	178	3,064	697
1999	3,118	863	1,063	212	3,213	686
2000	2,598	785	1,022	229	3,270	711
2001	2,739	778	1,103	176	3,721	686
2002	2,630	750	1,126	174	3,516	616
2003	2,452	771	1,117	168	3,810	713
AAG	-1.68%	-0.42%	-1.76%	-1.68%	5.12%	3.40%

Table I.7 shows the forecasted non-coincidental total peak demands for each of the states for Fiscal Year 2006 through Fiscal Year 2015. The AAG is shown at the bottom of the table for each state. A total system peak demand is not given since the individual state peak demands occur at different months and hours for the fiscal year.

Table I.7 – Forecasted Non-Coincident Net Control Area Peak Load (MW)

Fiscal year	OR	WA	WY	CA	UT	ID
2006	2,664	795	1,004	156	4,131	708
2007	2,552	788	1,003	162	4,363	661
2008	2,577	806	1,018	166	4,600	661
2009	2,617	827	1,037	169	4,822	660
2010	2,638	850	1,060	172	5,050	663
2011	2,652	871	1,040	176	5,280	662
2012	2,666	894	1,058	180	5,507	664
2013	2,713	906	1,074	182	5,718	661
2014	2,771	931	1,097	186	5,950	667

Fiscal year	OR	WA	WY	CA	UT	ID
2015	2,814	956	1,117	191	6,196	672
AAG	0.61%	2.08%	1.20%	2.24%	4.61%	-0.59%

APPENDIX J – RENEWABLE GENERATION ASSUMPTIONS

BACKGROUND

PacifiCorp currently purchases 124 MW of wind energy from wind resources located in Wyoming and Oregon. In addition, PacifiCorp provides integration services for more than 200 MW of wind power from projects located in Wyoming and along the eastern Oregon/Washington border and is currently in the process of evaluating proposals for additional renewable power. Renewable generation is a fast growing segment in PacifiCorp's supply stack. This section will review the following topics.

- Renewable Generation in the 2003 IRP
- Wind Generation Capacity Contribution
- 2004 IRP Renewables Assumptions
- Renewable Generation Costs and Benefits

RENEWABLE GENERATION IN THE 2003 IRP

PacifiCorp's January 2003 IRP identified 1,400 MW of renewable resources as part of the least cost portfolio of resources. In that analysis, generic wind resources were used as a proxy for all renewable resources due to the relative abundance of wind resources and its perceived cost-effectiveness. Capital and O&M costs of wind generation were relatively well known at that time, however other factors such as the value of the power, cost of integrating wind with the rest of the power system, and transmission from site-specific locations, were less understood. The 2003 IRP assumed no contribution to meeting peak demands from wind resources, due to the inherently variable nature of wind generation, without associated firming and shaping products. The amount of renewable resources added to the portfolio was based on an estimate of the availability of economic projects and acknowledged that PacifiCorp will continue to "learn as we go".

The 2003 IRP established that 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 renewable resources were also less susceptible to highly variable fuel costs in the risk analysis.

Since the 2003 IRP, PacifiCorp has developed modified assumptions on some of the factors that impact the comparative value of renewable generation, and in particular wind generation, to other traditional generation resources. Many of the uncertainties identified in the 2003 IRP remain but PacifiCorp is committed to continue to pursue renewable generation as a viable solution to meeting customer demand. The issue of the contribution of wind generation to meeting peak loads has been revisited in a modeling study separate from the IRP. In addition, the cost of integrating wind into PacifiCorp's system has been updated. More detail on these topics follows below.

CAPACITY CONTRIBUTION

This section describes the methodology and results of a study conducted by PacifiCorp to determine the portion of wind generating capability that contributes to meeting PacifiCorp's planning reserve margin. The analysis provides a comprehensive valuation of wind energy resources.

PacifiCorp adopted a 15% planning reserve margin above peak system load as a standard for reliability.[25] The planning reserve margin target takes into account the uncertainties of critical system assumptions such as load variability and unplanned outages of thermal resources. Conventional resources such as coal-fired steam turbines or combined cycle gas turbines are assumed to contribute their full nameplate capability towards meeting the planning reserve margin. In this case, the fuel source is considered to fully contribute to meeting the planning reserve margin, providing sufficient cushion for unit outages that may occur during these high demand times. The highly volatile nature of wind generation suggests using a fractional amount of their capability rating as their contribution to meeting planning reserve margin.

Unique Characteristics of Wind Generation

Wind resource performance is based on mechanical availability as well as wind performance (speed and variability). The relatively high probability that the resource may not be available when needed to meet peak load drives the need for a separate calculation of planning reserve contribution. An adequate contribution level should reflect the probabilistic nature of a wind resource's generation during the system peak

Several factors drive the measure of wind generation's capacity contribution in PacifiCorp's system. The first of these factors is site performance. For example, wind speed and duration are characteristics which directly impact site generation and the capacity factor of a particular wind site. Seasonal and diurnal patterns to characteristics help determine wind contribution during peak hours. The composition of the existing resource mix is also an important factor. The pre-existing volatility in system loads and resources affect wind generation's capacity contribution.

Lastly, transmission plays a key role in determining wind generation's contribution to planning reserves. If a location is already transmission constrained (i.e. supply is unable to travel to the major load centers), then wind, as well as any other resource additions, will contribute relatively less toward planning reserves due to the reasons cited above having to do with the pre-existing system volatility. In addition, proposals are surfacing to site wind projects where firm transmission is not available all the time. For sites where the transmission congestion is a rare event, but normally occurs during peak loads, contribution to planning reserve margin may be effectively nonexistent.

Third Party Studies

The study of wind generation on system reliability, or its effective capacity contribution, has been performed by other major utilities. The Colorado Public Utilities Commission ordered Xcel Energy to undertake 'good faith negotiations' for a wind plant as part of their integrated resource

[25] See Appendix N for more discussion on planning margin.

plan (Lehr et al). As a consequence, Xcel undertook a study, the first of its kind, to determine a capacity value for wind, via a joint effort of several organizations[26]. The study applied the methodology outlined by Michael Milligan from the National Renewables Energy Laboratory (NREL).

Xcel focused on identifying the cost and control performance impacts of integrating an existing, 162-MW wind plant near Lamar, Colorado, into Xcel Energy's North control area. Xcel first determined the 'conventional' energy equivalent when adding these wind resources. To find the conventional energy equivalent, Xcel employed a Monte Carlo type simulation, in conjunction with Markov probability transition states, to simulate the actual generation at their wind site. The Markov probability transition states provide the random process typically present in Lamar site's hourly wind generation. The analysis determined that the wind plant would provide the equivalent reliability benefits of 49 MW of conventional generation for approximately a 30% contribution to planning reserve margin calculation.[27, 28]

Other studies used simpler techniques, such as applying a seasonal capacity factor associated with peak load. The results of the studies varied from a contribution of only 10% for ERCOT and Cal ISO, to 20% for the PJM.

Application to PacifiCorp's System

Methodology

PacifiCorp followed the methodology outlined by NREL and Xcel Energy to determine a reasonable capacity contribution for wind resources on its system. PacifiCorp employed the 2004 IRP model. A single year base case model run was used to set the level of energy not served (ENS) for the system during the peak load month of July under typical operations with resources built to the planning reserve margin of 15%. Next, a single wind resource with hourly varying output was added to a location in the system and the resulting lower level of ENS was noted. To determine the equivalent capacity contribution provided by the wind resource, the hourly load in that location was proportionately increased until the ENS was equal to the base case amount. Three sizes of wind resources were tested, 50, 100 and 150 MW within each load center of the system.

Study Assumptions

Although wind sites may occur in several trans-area locations of the IRP model, study wind sites were limited to five locations in interest of model run-time. The five areas chosen are believed to be representative of all types of constraints or benefits that are possible within PacifiCorp's system. There are three study sites in the western control area: West Main, Washington, and Mid-Columbia. There are two study sites in the eastern control area: Utah North and Wyoming. These sites are some of the potential development sites for future wind projects. These locations offer a variety of transmission alternatives, as well as a variety of supply side components.

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[26] DeMeo, E., et al. "Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning." Xcel Energy – North Case Study Final Report. May 2003

[27] Lehr, R.L., J. Nielson, S. Andrews, and M. Milligan. "Colorado Public Utility Commission's Xcel Wind Decision." NREL/CP-500-30551, September 2001

[28] Milligan, M.R., "Modeling Utility-Scale Wind Power Plants, Part 2: Capacity Credit." NREL/TP-500-29701, March 2002

Modeling Assumptions
Separate site characteristics were used for new wind resources on the East and West sides of the system. The wind additions were modeled with essentially no hourly or monthly correlation between regions. These two capacity shapes capture the diversity of the wind resource across the system. Based on historical performance of a confidential wind resource on the west side of PacifiCorp's system and Foote Creek on the east side of the system, an average annual capacity factor of wind was assumed to be approximately 29.8%. The average July capacity factor was assumed to be 18.7%.

Unlike the deterministic modeling used for valuing portfolios in the IRP, a probabilistic method was used for this study with the average of five runs used to arrive at the ENS values for each scenario. The probabilistic tool used convergent Monte Carlo simulation to vary the model parameters of load, hydro generation, electric market prices, gas market prices, and thermal resource outages. PacifiCorp employed Henwood's probabilistic tool embedded in the MARKETSYM model. This process involves modeling hourly wind generation data with a representative Probability Transition Matrix applied to a set of hourly generation states. The Generation State Matrix in Table J.1 shows the blocks of potential hourly output levels by month for a 50 MW wind site.

The Probability Transition Matrix is a 6 x 6 matrix whose entries represent the probability of moving from one state to another. The first state, or State 0 represents 0 MW of generation. The probabilities are a result of developing a histogram of the hourly data.

Table J.1 – Generation State Matrix: Modeled Generation States for a 50 MW site (MW)

Month	State 0	State 1	State 2	State 3	State 4	State 5
Jan	0	8.5	20	27	35	48
Feb	0	8.5	19	27	33	46
Mar	0	6	18	26	31	46
Apr	0	6	17	24	31	44
May	0	5	15	22	30	44
Jun	0	5	15	22	26	43
Jul	0	4	10	17	24	42
Aug	0	4	10	17	24	43
Sep	0	5	13	18	27	44
Oct	0	6	14	20	33	46
Nov	0	7.5	16	25	34.5	48
Dec	0	8	18	26	35	48

The generation values in Table J.1 are doubled and tripled for the 100MW and 150MW wind farms. From the hourly data it is relatively straightforward to calculate the probability of moving from one state to another. The Probability Transition Matrix is illustrated in Table J.2. The left-hand side of the table represents the generation state in the previous hour, and columns representing the state in the subsequent hour. For example, there is an 85.6% chance that if the wind unit is generating no output on an hour, it will generate no output in the subsequent hour. If the wind farm is generating in State 1, then the model accords a 55.4% chance of remaining at the State 1 generation level in the next hour. The same Probability Transition Matrix is applied to all Generation State Matrices.

While the model allows specification of different generation levels by month (Table J.1), the Probability Transition Matrix (Table J.2) must remain fixed for each generating station over the year.

Table J.2 – Probability of Moving from One Generation State to Another

Probability of Moving to Next Block (%)	State 0	State 1	State 2	State 3	State 4	State 5
State 0	85.6	12.4	1.5	0.4	0.1	0.0
State 1	23.0	55.4	17.5	3.2	0.8	0.1
State 2	23.0	22.7	50.4	20.1	4.0	0.1
State 3	6.0	4.7	20.7	50.3	22.8	0.9
State 4	0.1	0.8	2.6	13.8	72.7	10.0
State 5	0.1	0.2	5.0	6.2	27.1	61.4

The study began by establishing a base case set of energy not served (ENS) in each of the load centers. The base case ENS was the starting point upon which all subsequent scenarios were compared.

Results

Table J.3 shows the results of the analysis for each size of wind site at each location based on the corresponding increase in load for each scenario.

Table J.3 – Estimated Capacity Contribution by Wind Resource Size and Location

Location	50 MW*	100MW*	150 MW*
Mid-C	23%	23%	21%
UT-N	17%	21%	21%
Washington	24%	24%	23%
West Main	22%	22%	21%
Wyoming	21%	17%	17%

*As percent of nameplate

Generally speaking, the wind farm locations in the western control area had a higher effective contribution than in the eastern control area. The average contribution for all eastern wind resources, including all capacity values, is 19%. The average value for all western wind resources is 23%. The overall average is 21%.

Conclusion

This study used only one generation shape, and one probability matrix, resulting in one capacity factor during the month of July, that being approximately 19%. The probability outage matrix results in a probabilistic production pattern that is indifferent to time of day. As a consequence, results of this study do not reflect wind patterns with strong diurnal patterns, which is often the case. In conclusion, due to the results of this study with its conservative performance assumptions, PacifiCorp adopted a 20% capacity contribution toward the planning reserve margin in this IRP for wind resources. This is a change from the 0% capacity contribution assumption used in the 2003 IRP.

2004 IRP RENEWABLES ASSUMPTIONS

Renewable assumptions used in the 2003 IRP and progress made since have greatly influenced the assumptions in place for the 2004 IRP. The most significant change in assumptions is the 20% capacity contribution for wind resources. With wind able to contribute to the planning reserve margin target, fewer additional resources will be required, lowering the portfolio capital cost and the total portfolio PVRR.

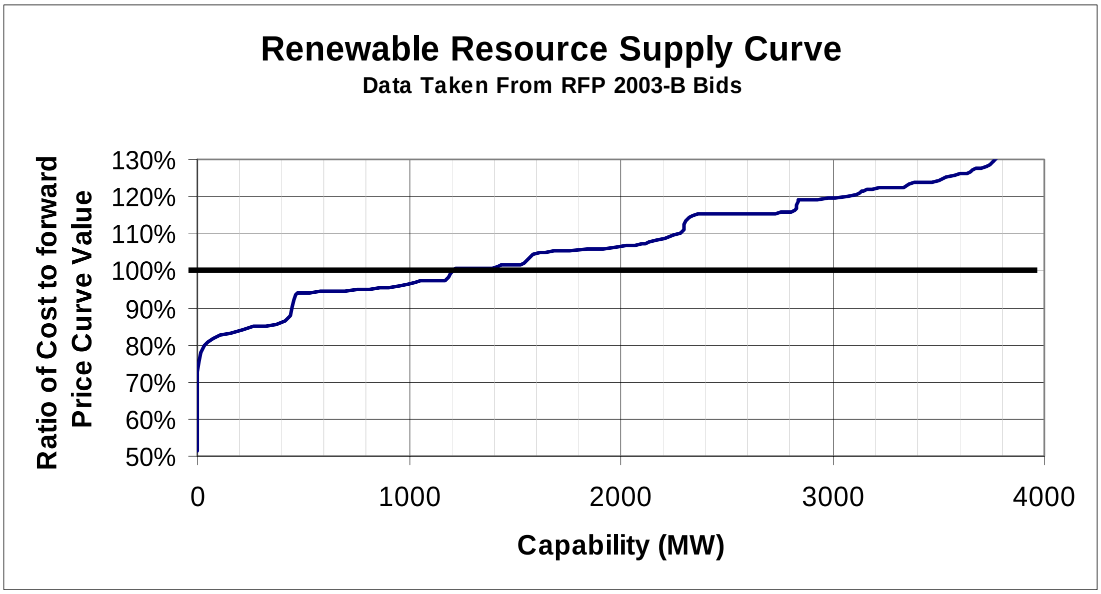
For the 2004 IRP, PacifiCorp retains the IRP 2003 conclusion that the 1,400 MW of renewables, modeled as wind resources, will continue to be cost effective and help to lower the overall system costs by reducing emissions and fuel costs. The 1,400 MW will contribute a total of 280 MW to the planning reserve margin target. PacifiCorp concludes that it is valid to assume 1,400 MW of renewables in the base case for this IRP based on the review of RFP 2003-B responses, and experiments with Henwood's Capacity Expansion Model (CEM) described below.

RFP 2003-B Responses

As a result of the 2003 IRP, PacifiCorp issued RFP 2003-B in February 2004, a request for proposals for renewable generation. More than 6,000 MW of generating capability were offered, of which 85% were from wind resources. These bids added specificity to the quantity, location, and cost of wind resources available to PacifiCorp. PacifiCorp proposes using the cumulative bids to RFP 2003-B as representative of the amount and cost of renewable resources to be used in the 2004 IRP. These representative values include the transmission and integration costs of additional wind resources that would be procured up to, but not beyond, the amount of resources considered in the 2003 IRP. PacifiCorp recognizes that the proposals received into RFP 2003-B are not necessarily representative of renewable resources which may become available in later years. Prospecting for wind sites should continue and improve over time. Additionally, not all of the proposals recently received may prove viable. Nevertheless, the bids represent the best information available at this time on the quantity and cost of renewable resources specific to PacifiCorp's system. The bids may be used as a reasonability check on the 1,400 MW IRP 2003 assessment.

Figure J.1 below shows the cumulative results of the bids into RFP 2003-B. A ratio representing the cost effectiveness of bids is formed by dividing the present values of proposed cost of the bids (including assumed integration costs, third-party wheeling if applicable, and an estimation of applicable transmission upgrades) by the expected market value of the power generated (including environmental attributes). The expected market value of power is the same version of the forward price curve as used in the 2004 IRP.[29] Ratios less than 100% are cost effective compared with PacifiCorp's expectation of the value of the power. The figure indicates that from 1,200 to 1,600 MW of proposed resources appear to be cost effective according to the evaluation methodology and bidders' representations. It is important to keep in mind, however, that PacifiCorp is in the process of validating the specifics of the information provided by the most economic offers received. Also note that all bids included in the curve assume that the Production Tax Credit (PTC) will be available for the first ten years of operation, regardless of plant installation date. Currently, the PTC has been extended only through December 2005.

Figure J.1 – Cumulative Results of the RFP 2003-B Bids



Two countervailing factors cloud the applicability of this data as definitively representative of a supply curve for renewable resources. It is unusual for all bids into any RFP to turn out to be viable. Many factors, including access to capital, assumptions regarding transmission availability, and a mutual understanding of bid requirements come into play. On the other hand, the data presented represent only those resources that have been sufficiently developed to date to merit consideration. Many developers have made clear that they will continue to develop projects, some physically co-located with the offered bids, that are not presently ready to be offered, but are likely to become ready over the next few years. In short, the data is not perfect, but represents the best estimate currently available.

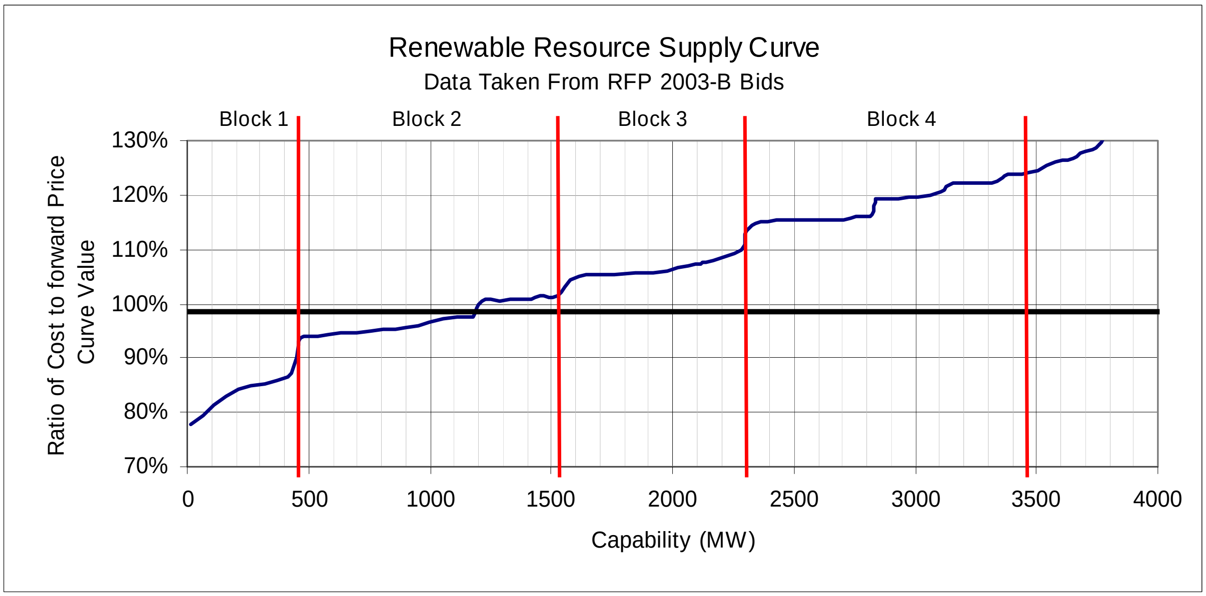
Modeling Resource Selection of Renewables

As Figure J.1 shows, data from RFP 2003-B appear to lend credibility to the IRP 2003 renewable resource target level. To further test the reasonableness of incorporating 1,400 MW of wind resources as a base case assumption, the renewable resource supply curve was added to Henwood's Capacity Expansion Model (CEM). The CEM tool was then allowed to select the size, timing, and price of renewable generation which best meets the needs of the system along with other traditional resources.

[29] PacifiCorp's forward market prices dated June 2004 were used for this analysis.

Some simplifying assumptions were made to represent the renewable supply curve within the CEM. The curve was divided into four blocks of generation according to price relative to the forward market price (Figure J.2). A total of 3,400 MW of wind resources were added to the model and split equally between the East and West control areas. Although the supply curve includes multiple bids during differing years, the assumption was made that all the capacity is available beginning in FY 2007. A more conservative assumption was used for the first year of the plan where the base case 100 MW in the West remained unchanged. Thereafter, 3,400 MW of renewable power was available each year for selection by the tool unless the units were selected in previous years.

Figure J.2 – Supply Curve with Blocks



Pricing

The RFP Bid supply curve represents an estimate of the magnitude and pricing of new renewable generation relative to the forward market prices. In Table J.4, each block price is referenced to a percent of the forward price curve. The total \$/MWh cost of the new resource blocks was calculated by taking the present value of 20 years of forward market prices using the install year as the base year and applying the block pricing factor. The block pricing factor is the average percent of market prices assigned to that block. For example, the block pricing factor for Block 1 is 83% and Block 2 is 98%. The result is eight blocks of renewable resources, priced for nine years of potential installation. The Mid-Columbia market was used to price the West resources and the Palo Verde market was used in the East.

Table J.4 lists the block sizes and prices relative to the forward market prices by year for each control area. All units are modeled as 50 MW capacity, therefore Block 1 in 2007 totaling 250 MW is composed of five 50 MW units priced at 83% of forward market prices. Once a unit is selected, it is no longer available for selection in later years. The model adds capacity to maintain at least a 15% planning reserve margin. Since most of the renewable resources in the supply curve are wind generation, the blocks added to the CEM were assumed to be wind generation and 20% of their capacity was applied toward the planning reserve margin requirement.

Table J.4 – Renewable Block Design

	Block 1	Block 2	Block 3	Block 4	Total
Size (MW)	250	500	400	550	1,700
# of Units	5	10	8	11	34
Price % of FPC	83%	98%	109%	120%	106%

Results

Other than 100 MW of base case renewable generation assumed in FY 2006, the CEM tool was allowed to select the optimum amount and timing of additional resources from FY 2007 through FY 2015. Table J.5 shows the total capacity of renewable resources selected by year and the total capacity contribution to planning reserve margin by resource type. Wind resources are assumed to have a 20% effective load carrying capability as reflected in the Total Capacity Contribution column.

Table J.5 – Selected Renewable Resources

Area	Resource	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	Total
East	Brownfield PC Subcritical						575					575
	Greenfield PC 2								383			383
	CCCT (2x1) - (Dry Cooling)				420					420		840
	Dry CCCT Duct Firing (2x1)				105					105		210
	Block 1 East		50			150		50				50
	Block 2 East								250	50		60
West	Greenfield CCCT 2x1 - (Dry Cooling)								469			469
	Greenfield CCCT Duct Firing 2x1 - (Dry Cooling)								117			117
	Base Renewables	100										20
	Block 1 West		100	50			100					50
	Block 2 West		50	50		100		200				80
	Block 3 West										50	10
	TOTAL MW	100	200	100	525	250	675	250	1,219	575	50	2864

Conclusions

The magnitude and pricing of the projects received in response to the RFP 2003 B are an encouraging reflection of the availability of cost-effective renewable resources. The resource selection tool recognizes the value of these renewable resources for optimizing the total portfolio costs by selecting 1,250 MW over nine years.

PacifiCorp concludes that it is reasonable and prudent to assume that 1,400 MW of cost effective renewable resources can be acquired over the next ten years, and proposes to 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.

RENEWABLE GENERATION COSTS AND BENEFITS

A number of considerations should be taken into account when integrating wind energy into PacifiCorp's power system. There are costs and benefits which must be calculated specifically for wind due to its renewable and clean, yet, short-term volatile nature. These additional costs and benefits need to be estimated in order to understand the relative value of wind energy compared with other resources. The methods developed to estimate those costs are described in this section, along with the results of applying the methods to PacifiCorp's system. Although these costs and benefits were not explicitly modeled within the 2004 IRP since the 1,400 MW of renewable power additions were fixed costs in the base case, having a thorough understanding of resource costs is necessary for RFP evaluations.

- Integration costs
- Green tag value
- Production Tax Credit

Wind Integration Costs

PacifiCorp developed a methodology for calculating the added cost of integrating wind resources into the system during the 2003 IRP. This section will provide a brief review of the methodology and update of the original assumptions.

Utilities maintain reliability by dynamically responding to imbalances in demand and supply. Resources are scheduled to ramp in generation when loads are increasing, and to reduce generation as loads subside for the day—other resources are made available to respond on a near instantaneous basis. Flexible resources that can change their output over periods of hours and seconds are key to responding to the rapid changes in loads and unexpected changes in resource output (outages and derates). It is expected that additions of wind resources will increase the need for flexible resources to meet reliability standards.

The amount of unloaded, relatively flexible resources available on any hour is called the *operating reserve*—resources available on short notice to provide additional power as needed. Calculating the quantity of reserves required to maintain system reliability has not been an exact science as practiced in the utility industry. Many years of experience with thermal and hydro resources has lead to some industry standards. One such standard is to maintain contingency reserves[30] equal to the sum of 5% of load served by hydro resources and 7% of load served by non-hydro resources operating to meet load on any hour. In general, utilities are required to have sufficient operating reserve to meet the North American Electric Reliability Council (NERC) performance standards.

In addition to needing to assure sufficient flexible resources available to meet demand obligations, PacifiCorp needs to understand the extent to which the system incurs additional operating costs associated with the relatively volatile and less-predictable nature of wind generation. Those costs are termed *Imbalance Costs* for the purpose of this paper[31].

[30] Contingency Reserve is a category of Operating Reserve that must be made available to quickly respond when some portion of the power system experiences a failure such as transmission line outages, generator failures, etc.

[31] Note that the term Imbalance Cost as used in this paper is not directly related to the definition of imbalance charges found in FERC pro-forma transmission tariffs. As used in this paper, imbalance costs refer strictly to the additional operating expenses incurred as a result of adding wind generation to the system. Such costs may include the costs of additional market sales and purchases, more frequent unit startups, and the cost of dispatching reserve units.

Because of the implications for reliability and PacifiCorp's role as control area service provider, PacifiCorp undertook to define methods of assessing both incremental reserve requirements, and additional dispatch costs due to integrating wind resources on its system. While it is clear that the methods employed will require future refinements, PacifiCorp feels that they represent a reasonable approximation for estimating wind integration costs given the characteristics of PacifiCorp's control areas until further analysis can be undertaken.

Imbalance Costs

For the 2003 IRP, Henwood's MARKETSYM model was used to estimate the difference in system costs[32] between firm contract delivery at constant rates over time, and an equivalent amount of energy from simulated wind resources. Wind generation fluctuated hourly based on available historical wind data.[33] The alternatives were tested for wind and contracts separately on the west and east sides of PacifiCorp's system. The model was run for three future years at five levels of added wind capacity and averaged to estimate imbalance costs.

The model showed relatively little difference between the east and west sides of the PacifiCorp system. At wind penetration levels of 1,000 MW MARKETSYM reports average imbalance costs of about $3/MWh in year 2002 dollars.

Incremental Operating Reserve Requirements

Incremental reserve requirements were estimated by comparing the relative dynamic range of loads with and without wind. The standard deviation of hourly loads for a year was calculated. A new standard deviation was computed after subtracting out various levels of wind generation. The fractional difference in standard deviations was taken as an estimate of the increased need for operating reserves.

Assuming that the fractional increase in standard deviation of hourly loads with and without wind is proportional to the increased need for reserves, the incremental need for reserves can be estimated. Factoring in the cost of reserve results is an estimation of the cost of incremental operating reserves attributable to wind.

Operating reserves are typically held on hydro units when available, and higher variable cost thermal units to the extent they are needed. PacifiCorp holds an existing portfolio of resources that can be arranged from highest variable cost to lowest. Holding reserves on unloaded flexible hydro units, and above-market-cost thermal units incurs relatively little cost. For these reasons, some wind site locations supported by flexible generation within the system may be preferable over other locations. However, as the need for reserves increases, the likelihood of having to carry reserves on economic thermal units and loaded hydro units increases. This means that the

[32] System costs = dispatch costs + market purchase costs – market sales revenues

[33] The hourly wind sites modeled in this study were based on simulated historical hourly generation data from a wind resource on PacifiCorp's west system and Foote Creek on the east system. The two data streams were modified by lagging by one hour and moving data ahead one hour to create four new data ranges for the model. The two west side streams were added together and then sized to the installed capacity level for the West side site. The two new Foote Creek sites were combined and prorated up to the various installed capacity levels for the East side site. A single year of hourly generation was repeated for each of the three years of the study.

cost of holding reserves increases with the level of reserves being held. Costs of holding reserve may increase or decrease over time due to changes in overall market prices[34].

Caveats

The foregoing analysis is thought to represent a reasonable approach to estimating costs associated with integrating wind resources into PacifiCorp's power system until further analysis can be performed. Many assumptions have necessarily been made to do this analysis. Some of the main assumptions include:

- MARKETSYM's ability to accurately reflect imbalance costs
- Operating reserve requirements are proportional to hourly load volatility net wind generation
- Sufficient transmission to fully integrate wind resources with the system
- Intra-hour variability is not significant

Updates to Wind Integration Costs

At a penetration level of 1,000 MW, the cost of incremental operating reserves in the 2003 IRP for a wind site with a capacity factor of 30% was $2.72/MWh. Combined with the $3.00 /MWh estimate for imbalance, the total integration cost for 1,000 MW was approximately $5.50/MWh.

Since this analysis was first completed, the assumption for imbalance costs have remained unchanged at $3.00 / MWh in 2002 dollars but the cost of incremental reserves has been updated for new market prices. The same methodology was used in the update, only the cost of reserves was adjusted. Currently for 1,000 MW of wind capacity split equally in the system, the 20 year levelized cost of integration in 2004 dollars is estimated to be $4.64 / MWh.

<u>Green Tag Value</u>

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

Green tags are the result of policy incentives to encourage renewable energy production. Potential green generation mandates like a Federal Renewable Portfolio Standard or similar state requirements may be met with the purchase of green tags and therefore can be valuable to utilities with renewable generation above the required level. At present, there is no federal RPS. Furthermore, PacifiCorp's service territory does not include states that require a RPS, with the exception of California. In Washington State, House Bill 2333 is currently under consideration. This bill targets 5% of all energy needs being met with renewable generation by 2010, 10% by 2015, and 15% by 2023. In addition to providing renewable generation, utilities would be required to implement cost effective energy efficiency programs to lower their customer demand by 0.75% from 2006-2009, increasing to 0.85% reduction from 2010 forward. Independent of legislative requirements, utilities in the future could set proprietary renewable targets independent of a RPS.

[34] The cost of reserves also changes over hours and season. This calculation assumes an average cost over the year.

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

- **No RPS**: Where a Renewable Portfolio Standard does not exist and apply to PacifiCorp, green-specific energy would not be required for PacifiCorp's consumption. Thus, all tags would be available for trading.
- **RPS Implemented**: Where a RPS is implemented, PacifiCorp's renewable generation can allow it to avoid the market costs of procuring tags. Tags for generation above the standard would be marketable.

While retaining some value independent of a legislative mandate, the amount of that value is uncertain. For modeling assumptions, new wind and geothermal plants are assumed to have a green tag value of $5/MWh for the first five years of production. This rate does not change through time, effectively reducing their value by inflation each year. Such a value corresponds to our observations of the regional market for green tags, since the value translates into roughly $2/MWh when levelized over a 20-year purchase period. It would be expected that RPSs with strong targets for renewables development would lead to an increase in RPS value, as can be observed in other regions with RPSs including Texas and New England.

<u>Production Tax Credit</u>

The Production Tax Credit (PTC) incentive applies to new wind and geothermal plants with the intent of bringing their costs in line with traditional thermal resources. In the 2004 IRP, the tax credit applies to wind projects and "closed-loop" biomass projects (e.g., tree plantations devoted to supplying power plants) for the first 10 years of operation at $18/MWh. The credit would also apply to new geothermal and solar plants but only for the first 5 years of operation. "Open-loop" biomass (e.g., urban wood waste, agricultural prunings, etc.), landfill gas, and hydro sited on irrigation networks can earn 0.9 cents/kWh for five years. Annual net operating expenses are directly credited at $18/MWh for each MWh produced by wind and geothermal plants for each year the incentive applies. This is an effective simplification for applying the cost. In reality, the benefits of the tax credit do not apply to the bottom line in such a straightforward manner. The PTC was recently extended by Congress through December 2005. Based on historical experience, PacifiCorp expects continued renewal of the PTC past 2005 for long term planning purposes.

APPENDIX K – STANDARDS AND GUIDELINES

PACIFICORP COMPLIANCE WITH IRP STANDARDS AND GUIDELINES

Background

Least-cost planning (i.e., Integrated Resource Planning) guidelines were first imposed on regulated utilities by State commissions in the 1980s. Their purpose was to require utilities to consider all resource alternatives, including demand side measures, on an equal comparative footing, when making resource planning decisions to meet growing load obligations. Integrated Resource Planning (IRP) rules were also intended to require utilities to involve regulators and the general public in the planning process prior to making resource decisions, rather than after the fact.

PacifiCorp prepares an IRP for the states in which it provides retail service. While the rules among the jurisdictional states vary in substance and style concerning IRP submission requirements, there is a consistent thread in intent and approach. PacifiCorp is required to file an IRP every two years with most state commissions. The IRP must look at all resource alternatives on a level playing field and propose a near-term action plan that assures adequate supply to meet load obligations at least cost, while taking into account risks and uncertainties. The IRP must be developed in an open, public process and give interested parties a meaningful opportunity to participate in the planning.

This Appendix provides a discussion on how PacifiCorp complies with the various state commission IRP Standards and Guidelines in the preparation of this IRP. Included at the end of this Appendix is a matrix that provides an overview and comparison of the rules in each state for which IRP submission is required.[35]

General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with the State Commissions. The preparation of the IRP is done in an open public process with close consultation of all interested parties, including Commissioners and Commission staff, customers, and other stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and also serves to inform all parties on the planning issues and approach. The public input process for this IRP, further described in Appendix B, fully complies with the Standards and Guidelines.

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future loads of PacifiCorp customers and the capability of existing resources to meet this load.

[35] California and Wyoming requirements are not summarized in the matrix. The Wyoming requirements are discussed in the chapter text. California guidelines exempt a utility with under 500,000 customers in the State from filing an IRP; therefore, PacifiCorp will submit the IRP in California as an advisory filing only.

To fill any gap between changes in loads and existing resources, the IRP evaluates all available resource options, as is required by State Commission rules. These resource alternatives include supply- and demand side alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapter 6, meets this requirement. The evaluation of the alternatives include factors including impact to system costs, operations and reliability, and the impacts of numerous risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western electric system. The models allow for a rigorous testing of all the available resource alternatives available to PacifiCorp. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described in Chapter 5.

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as capital requirements vs. risk, and varying levels of reliability. This portfolio analysis and the results and conclusions drawn from the analysis are described in Chapters 8 and 9.

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan (See Chapter 9). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service. Chapter 9 also describes PacifiCorp's approach to procurement, and how it will adapt to changing circumstances as the future unfolds and uncertainties are resolved or evolve. Appendix M provides a progress report that relates this IRP to the previously filed 2003 IRP.

The IRP and this Action Plan are filed with each Commission with a request for prompt acknowledgement. Acknowledgement means that a Commission recognizes the IRP as meeting all regulatory requirements at the time the acknowledgement is made. In the case where a commission acknowledges the IRP in part or not at all, PacifiCorp works with the commission to modify and re-file an IRP that meets acknowledgement standards.

State Commission acknowledgement orders or letters typically stress that an acknowledgement does not indicate approval or endorsement of IRP conclusions or analysis results. Similarly, an acknowledgement does not imply that favorable ratemaking treatment for resources proposed in the IRP will be given.

California

Subsection (i) of California Public Utilities Code, Section 454.5, states that utilities serving less than 500,000 customers in the state are exempt from filing an Integrated Resource Plan for California. PacifiCorp only serves 42,000 customers in the most northern parts of the state. Consequently, PacifiCorp filed for and received an exemption on July 10, 2003 for the 2003 IRP. PacifiCorp expects a similar exemption to be granted for the 2004 IRP.

Idaho

The Idaho Public Utilities Commission's Order No. 22299, issued in January 1989, specifies Integrated Resource Planning requirements. The Order mandates that PacifiCorp submit a Resource Management Report (RMR) on a biennial basis. The intent of the RMR is to describe the status of IRP efforts in a concise format, and cover the following areas:

> *Each utility's RMR should discuss any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand and supply side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold*.

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2005, and fully addresses the above report components. The IRP also evaluates DSM using a load decrement approach, as discussed in Chapters 5 and 8. This approach is consistent with using an avoided cost approach to evaluating DSM as set forth in IPUC Order No. 21249.

Oregon

This IRP is submitted to the Oregon PUC in compliance with its guidelines and rules to perform Least-Cost Planning. Although the intent of the Commission is to use the IRP as a "working document" in rate case or other Commission proceedings, the Oregon PUC, in its Acknowledgement Order for the 2003 IRP, notes that "This order does not constitute a determination on the ratemaking treatment of any resource acquisition or other expenditures undertaken pursuant to Pacific's RAMPP-7 report." Further, "In ratemaking proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged least-cost plans."

Least-cost planning guidelines were first articulated in two Commission Orders: No. 89-507, "In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon", and Order No. 93-695, "In the Matter of the Development of Guidelines for the Treatment of External Environmental Costs"

Order No. 89-507, states that IRPs should adhere to the following principals:

- All resources must be evaluated on a consistent and comparable basis.
- Uncertainty must be considered.
- The primary goal must be least cost to the utility and its ratepayers consistent with the long-run public interest.
- The plan must be consistent with the energy policy of the state of Oregon as expressed in ORS 469.010.

The IRP should also be based on a 20-year planning period, consider competitive bidding in resource planning, regard rate design as a potential demand side resource, consider external costs, include a two-year action plan, and reflect cooperative planning with other states, the Northwest Power Planning Council, and the Bonneville Power Administration. Procedural elements that the IRP should adhere to include significant public involvement in plan preparation, protection of competitive secrets, and utility filing of interim IRP status reports.

This IRP abides by the above planning principals and procedures. Subsequent to the release of the 2003 IRP in January 2003, PacifiCorp issued a DSM RFP and two of the four planned supply side RFPs—RFP 2003-A and RFP 2003-B—for the acquisition of East-side flexible-dispatch and system-wide renewable resources, respectively. (See Appendix M for more details.) PacifiCorp also issued an interim IRP status report in October 2003 detailing an updated IRP analysis to account for new load forecasts, market price forecasts, network topology, and Hunter 4 implementation timeline.

Order No. 93-695 identified the cost adder approach as the preferred method for integrating external environmental costs into the resource planning process, as well as specifying other attributes of the impact evaluation framework, including offsets, geographic application, power purchases, the discount rate applied to future environmental costs, and fuel switching, among others. For this IRP, PacifiCorp continued its practice of using a cost adder and emission cap to capture CO_2 and NO_X emission costs. The approach for CO_2 has been augmented with the use of probability-weighted emission costs to reflect uncertainty in the start of a federal CO_2 emission reduction program. (See Appendix C, "Base Assumptions", for details.)

This IRP is consistent with the energy policy of the state of Oregon, as expressed in ORS 469.010(2)(a). This provision states: "That development and use of a diverse array of permanently sustainable energy resources be encouraged utilizing to the highest degree possible the private sector of our free enterprise system." In particular, PacifiCorp's Action Plan (Chapter 9) and Renewables RFP help advance this policy goal.

Utah

This IRP is submitted to the Utah Public Service Commission in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines"). The Order's key standards and guidelines, and how PacifiCorp complies with them, are discussed below.

The Utah Order states that the IRP process should "result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty." As in the last IRP, PacifiCorp subjected candidate resource portfolios to rigorous risk assessment and uncertainty analysis to determine the portfolio with the optimal cost/risk balance. In its effort to improve this optimization process, PacifiCorp is in the latter stages of validating an automated capacity expansion tool for use in the next IRP cycle. We expect the tool to significantly streamline the selection of portfolios to be evaluated further using criteria cited in the Utah Order -- alternative resource risks, externalities, uncertainty, and planning flexibility.

The Utah Order dictates that the IRP will include a "range of estimates or forecasts of load growth, including capacity (kW) and energy (kWh) requirements," and an "evaluation of all present and future resources, including future market opportunities (both demand side and supply side), on a consistent and comparable basis." This IRP addresses load growth forecast uncertainty by using a stochastic simulation approach to model load variability for each load center represented in the PacifiCorp system topology. This approach, described in Appendix G, uses both short-term and long-term variability parameters to capture a reasonable load growth range. Chapter 6 details all the candidate supply side and demand side resources considered during the portfolio building process.

The Utah rules require an analysis of the role of competitive bidding for resource acquisitions. PacifiCorp's Action Plan (Chapter 9) incorporates competitive bidding as an element of the Company's procurement program. As discussed above, PacifiCorp has issued two of four planned RFPs.

The Utah Order requires the IRP to include "an evaluation of the financial, competitive, reliability, and operational risks associated with various resource options…" In addition, the IRP needs to identify "who should bear such risk, the ratepayer or the stockholder." Chapter 4 discusses the types and sources of risk that were considered during the IRP process, the techniques used to evaluate these risks, and risk allocation considerations. The Utah rules also call for "an evaluation of cost-effectiveness of the resource options from the perspectives of the utility and the different classes of customers," and "a description of how social concerns might affect cost effectiveness." After discussions with Utah Commission staff, the approach used for the 2003 IRP to gauge retail customer rate impacts—with the modification to deduct depreciation from the retail rate—was deemed to meet the Order requirements. The rate impact analysis approach and results are discussed in Chapter 8.

Consistent with the Utah rules, PacifiCorp determination of Avoided Costs will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available.

The Utah rules call for a narrative describing how current rate design is consistent with the IRP goals and how changes in rate design might facilitate the IRP objectives. This narrative is provided in the Class 3 DSM Assessment section of Chapter 6.

Finally, Utah guidelines require PVRR to be expressed in terms of total resource costs. PVRR values provided in the report are based on total resource costs.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning (Washington Administrative Code 480-100-238). In addition to a Least Cost Plan, the rule requires provision of a two-year action plan and a progress report that "relates the new plan to the previously filed plan," This IRP complies with the process and substantive elements of the WUTC rules.

Wyoming

On October 4, 2001, the Public Service Commission of Wyoming issued an Order and Stipulation requiring PacifiCorp to file annual resource planning and transmission reports for a three-year time period beginning in 2002, each to be submitted on March 31, Each report "will address (1) load and resource planning issues affecting Wyoming, and (2) transmission investment, operation and planning issues affecting Wyoming." PacifiCorp submitted its last report in March 2004.

Table K.1 – Standards and Guidelines Summary

#	Topic	Oregon	Utah	Washington	Idaho
1	Source	Order 89-507 *Least-cost Planning for Resource Acquisitions* April 20, 1989.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251*Least cost planning* May 19, 1987.	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.
2	Filing Requirements	Least-cost plans must be filed with the Commission.	An Integrated Resource Plan (IRP) is to be submitted to Commission.	Submit a least cost plan to the Commission. Plan to be developed with consultation of Commission staff, and with public involvement.	Submit "Resource Management Report" (RMR) on planning status. Also file progress reports on conservation and low-income programs.
3	Frequency	Plans filed biennially. Interim reports on plan progress also anticipated.	File biennially.	File biennially.	RMP to be filed at least biennially. Conservation reports to be filed annually.
4	Commission response	LCP *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP *acknowledged* if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.
4	Process	The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Competitive secrets must be protected.	Planning process open to the public at all stages. IRP developed in consultation with the Commission, its staff, with ample opportunity for public input.	In consultation with Commission staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required.	Utilities to work with Commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.
5	Focus	20-year plan, with end-effects, and a short-term (2-year) action plan.	20-year plan, with short-term (4-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed.	20-year plan, with short-term (2-year) action plan. The plan describes mix of generating and conservation resources sufficient to meet current and future loads at lowest cost to utility and ratepayers.	20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.

Table K.1 – Standards and Guidelines Summary (Continued)

#	Topic	Oregon	Utah	Washington	Idaho
6	Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis • Uncertainty must be considered • The primary goal must be least cost, consistent with the long-run public interest • The plan must be consistent with Oregon energy policy • External costs must be considered, and quantified where possible. OPUC specifies specific environmental adders. • Identify to what extent the role of competitive bidding in planning for and acquiring new resources will be used • Avoided cost filing required w/in 30 days of acknowledgement	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds • A cost effectiveness methodology • An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders • DSM and supply side resources evaluated at “Total Resource Cost” rather than utility cost.	The plan shall include: • Range of forecasts of future demand; • Conservation technical assessment; • Assessment of feasible generating technologies, including purchases from other utilities; • A comparative evaluation of all alternatives on a consistent basis • All plans shall also include a progress report that relates the new plan to the previously filed plan.	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options; • Contingencies for upgrading, optioning and acquiring resources at optimum times; • Report on existing resource stack, load forecast and additional resource menu.

APPENDIX L – RESPONSE TO COMMENTS

COMMENTS ON THE DRAFT REPORT AND PACIFICORP'S RESPONSE

The IRP report was distributed in draft form to the public participants on November 5, 2004 and written comments were requested by December 3, 2004. The comment period was subsequently extended to December 10, 2004. PacifiCorp received comments from 14 parties. The final report reflects careful consideration of comments received. Additional comments will be considered in future iterations of the resource planning process. This Appendix summarizes the substantive comments submitted by the parties, and offers PacifiCorp's response. A list of the commenting parties is provided at the end of this Appendix.

<u>Action Plan</u>

Procurement

OPUC requests an indication of intentions to issue RFPs and conduct competitive bids to procure resources in the Action Plan and to specify what coal procurement actions are anticipated prior to acknowledgement of this IRP. UPSC asks if a viable benchmark resource will be used to evaluate RFPs. UPSC also requests clarification of how the \$8 CO_2 adder will be treated in future procurement activities.

Response: PacifiCorp intends to use a formal and transparent Procurement Program in accordance with the then-current law, rules, and guidelines in each of the states in which it operates.

The timeline to implement the CY 2009 and CY 2011 resource additions has the potential for some coal procurement action(s) prior to plan acknowledgement. For example, if the procurement process for the CY 2009 resource is an "all source" process, a third party supplier able to demonstrate the ability to meet the summer 2009 commercial operation date requirement with a coal resource. In contrast, if the procurement process for the CY 2011 resource excludes certain resource characteristics, such as a power plant that burns a fuel other than coal or is dependent on the construction of a material transmission line(s), then PacifiCorp would anticipate fewer resource alternatives. Consequently, this would impact the design phase of the process. In any event, PacifiCorp will continue to monitor the status of third party coal projects as well as build upon our existing knowledge of related coal technologies and potential coal sites.

Benchmarks will be determined prior to any RFP being issued. Such benchmarks may consist of the then-current view of market prices, self-build options, contractual arrangements or other such benchmark alternatives. 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 those of the IRP unless such assumptions are not applicable or new/updated information becomes available to inform the process.

General

UDPU and UCCS are concerned the draft Action Plan lacks specifics. UPSC suggests a more specific timeline for consideration of portfolios that depend upon regional transmission expansion, such as Portfolio Q.

Response: The Action Plan summary table (Table 9.2) combines both the findings of need and the implementation actions from the 2003 IRP into one table. In response to the comments, PacifiCorp has modified the Action Plan Implementation section of Chapter 9 to include projected timelines associated with procuring specific action items. This section has also been modified to include PacifiCorp actions for meeting the targets outlined in the summary table.

Assumptions /Modeling

Combined Heat and Power

WRA generally supports the analytical approach to CHP, and provides some suggested CHP modeling improvements. WRA also suggests an Action Plan item addressing the opportunity. OPUC requests a complete evaluation of available, realistic CHP sites. UAE comments that QF options appear to get limited consideration by the Company in this IRP. Other parties raised questions suggesting the narrative on QF options lacked clarity and perhaps was internally inconsistent.

Response: PacifiCorp believes that its approach to modeling CHP resources is sound based on current understanding of resource potential and operations. This approach includes using all current and available information to properly evaluate CHP as a resource. An important part of this approach is to evaluate potential CHP sites as per Action Item 8 of the 2003 IRP.

To estimate a realistic market size, PacifiCorp participated in the nationwide CHP study conducted by Primen. The final report, "Converting Distributed Energy Prospects Into Customers, Primen's 2003 Distributed Energy Market Study" was completed December 30, 2003. Based on customer input from facilities in the 100 kW to 10 MW size range, it concludes that 2% of the market are strong prospects and 11% are soft prospects for cogeneration over the next 5 years. This is about 100 MW in PacifiCorp's Utah market. This compares favorably to two previous Utah studies that projected 100-150 MW of realistic market potential. In Oregon, the realistic market is about 45 MW in the PacifiCorp service territory based on the Primen study results. This study can be provided on request.

Informed about potential CHP sites, PacifiCorp modeled 90 MW of new western CHP resources in a stress case. These modeled resources contributed full capacity towards the planning margin and provided energy with an 85% capacity factor. Also modeled were 100 MW of planned CHP resources in the east which were dispatched economically and contributed towards the planning margin. This allowed an accurate assessment of new and planned CHP resources in the PacifiCorp system.

The scope of the Primen study was to look at barriers to CHP development, and to assess a realistic market potential based on customer input. Specific site analysis, because it is expensive, is conducted based on customer interest. Customers surveyed in this study were asked if they wanted to be contacted by PacifiCorp to get further information on their potential CHP prospects. In partnership with the Regional CHP Application Center and Questar, PacifiCorp followed up with customers who wanted more information on CHP. In addition, all PacifiCorp account managers continuously work with their accounts regarding their energy supply situation and to identify cost saving solutions for customers, including DSM and CHP opportunities. Beyond these efforts, PacifiCorp continues to consider CHP as an eligible resource in all supply-side RFPs and has included CHP as an Action Item in the Action Plan of Chapter 9.

As was suggested, all narratives related to CHP have been modified to be consistent throughout the document.

Gas Price Forecast

UCCS states that the gas price forecast appears unreasonably low and the risk of gas-fueled resources is inadequately addressed in the IRP. The UCCS also indicates that a fundamental shift in the natural gas market, such as inadequate future LNG supplies, was not adequately addressed. MWC and UAE comment that the IRP study should be redone with a revised natural gas price forecast. On a forward-going basis, UDPU encouraged continued study of natural gas price uncertainty. UAE states that the IRP should address how gas purchasing practices may change in response to changes in price volatility and escalation trends.

Response: PacifiCorp believes that its process for evaluating natural gas risk is sound and helps to ensure the selection of low-risk portfolios. This is particularly important given the gas price increases that have occurred in recent months. A paper issued by PacifiCorp on November 8, 2004 explains how both IRP gas forecasts, reference and high, bracket the independent forecast of the DOE/EIA Annual Energy Outlook 2004.

PacifiCorp recognizes that the uncertainty of future gas prices is inescapable. Thus, IRP modeling efforts have focused attention on assessing the performance of portfolios given a range of uncertainty of future gas prices, not on asserting the accuracy of any particular forecast. PacifiCorp believes that the additional high gas price scenarios (see Chapter 8 and Appendix C), in combination with the stochastic simulations that recognize the potential for periods of extreme gas prices, do in fact adequately address gas price issues and risk.

PacifiCorp also believes that the assumptions underlying the natural gas price forecast are sound. One of the underlying assumptions that form the basis of the natural gas forecast is emergence of liquefied natural gas (LNG) as a global commodity and a significant source of North American supply. LNG imports are expected to grow significantly over the next decade as additional receiving terminals are constructed, adding to the current capacity of four such terminals now operating in the US. More than forty new terminals are currently in some stage of proposal or development in North America, although a much smaller number are likely to be completed. Similar infrastructure expansion of liquefaction terminals and LNG tankers is also underway. These trends support forecasts for growth in LNG imports from an estimated 1.6 bcf/day in CY 2004 to between 9 and 14 bcf/day by CY 2015. By comparison, domestic US gas production has averaged about 52 bcf/day over the last five years. PacifiCorp's analyses, including the new high gas price scenario and the stochastic analysis, encompass gas price uncertainty as it might be affected by the timing of LNG growth.

Appendix A has been expanded to provide detailed discussion on the natural gas market. Appendix C has also been updated to include a discussion of the gas forecast assumptions used in this IRP.

The natural gas section in Chapter 2 mentions that PacifiCorp developed a prudent and comprehensive natural gas strategy that includes hedging mechanisms to address changing commodity risks (availability and price). The core philosophy behind the strategy is to reduce the price volatility effects to which PacifiCorp's customers are exposed. Because PacifiCorp's strategy reduces volatility exposure by locking in long term pricing, there is no anticipated need to significantly change its gas purchasing strategy.

Front Office Transactions

UPSC raised concerns and asked for a more thorough explanation of the rationale for the assumed 1,200 MW of Front Office Transactions. UPSC also calls for discussion on the pricing strategy, i.e., fixed or indexed, that will be employed in Front Office Transactions, and implications of this strategy on risks. UPSC also asks for clarification of how Front Office Transactions will be subject to regulatory scrutiny. The UCCS indicates that the Front Office Transactions should have been subjected to stochastic and scenario risk analysis. UAE and MWC also call for more explicit review of Front Office Transactions.

Response: Chapter 3 and Appendix C in the 2004 IRP draft have been revised to address these issues. A response to the issue raised by UCCS is addressed in the Standards and Guidelines (#7) section of this Appendix.

Planning Margin

CUB states the IRP short changes the benefits of a short-asset strategy, and recommends reducing the planning margin to 12%.

Response: PacifiCorp has included a 15% planning margin (discussed in some detail in Appendix N) in its loads and resources balance, a level deemed adequate to ensure its obligation to serve load. Regarding planning margin criteria assumptions, PacifiCorp acknowledges that there is a tradeoff between cost and reliability within system planning. Greater system reliability comes with increased resource need. However, maintaining a level of resources which supplies a lower level of system reliability can also be costly due to expenses and penalties incurred during system outages; the optimum balance of cost and risk lies somewhere in between both extremes. PacifiCorp considered the reliability cost-risk tradeoff when determining the planning margin criteria of 15%, and this level of planning margin is consistent with what is being used by neighboring utilities and what is being proposed in recent resource adequacy initiatives.

Plant Lives of New Resources

ODOE requested model runs for coal and gas using various plant lives.

Response: Plant life is a fundamental modeling characteristic of a resource. Using a plant life other than that supported by PacifiCorp's technical and cost analysis studies, would skew the

PVRR analysis. Since the IRP compares resources based on least cost, adjusting plant life without supporting analysis would not yield a true comparison between resources.

The IRP process, by design, screens out unreasonably costly or risky resources and performs least cost and risk analysis on potentially viable resources. A thermal resource with a plant life not supported by analytical criteria would not be considered a tenable candidate for analysis in the IRP.

Resource Addition Logic

The UDPU expressed concern that PacifiCorp did not obtain the resource addition logic tool in a timely manner. UCCS states that since the resource addition logic was unavailable for the majority of the modeling, the optimal portfolio may have been missed. UCCS also comments that there was inconsistent use of the tool.

Response: During the 2003 IRP process, it became apparent that stakeholders in Utah were eager to see PacifiCorp incorporate Resource Addition Logic into its IRP process. In the spring of 2003, PacifiCorp decided to contract with the vendor of its existing IRP model (Henwood) to develop a tool (Capacity Expansion Model (CEM)) which would be designed to provide the resource addition logic. Henwood indicated they had installed a similar model in Europe, and that it would only have to be adapted for the PacifiCorp system. Unfortunately, during 2003 there was significant turnover in the IRP group which subsequently caused a delay in the acquisition of the tool. As soon as it became apparent that the effort was behind schedule, an aggressive timeline to acquire the CEM was agreed to with the vendor.

The delivery date for the CEM was scheduled to be July 2004; however the vendor indicated in April that the model would be delivered without the complete user interface making full use and validation of the model impractical. Because the model could not be fully validated, it could not be used as the primary vehicle for performing capacity expansions. The IRP group had no choice but to continue the manual portfolio build methods used in the 2003 IRP, and with regret, stated so throughout the public input process.

That being said, PacifiCorp believes that good things were achieved with the model in this IRP cycle. Most notably, it was used to generate a candidate portfolio that ran a close second in the PVRR rankings of the deterministic simulations. This portfolio informed the modeling process significantly because it included the size and timing of several resources similar to those in the Preferred Portfolio (see Chapter 7). This served to validate the manual build process as well as to provide some validation for the CEM itself. In addition, the model proved very helpful with adding Class 1 DSM programs to the preferred supply-side portfolio, and testing the assumption of 1,400 MW of planned wind resources.

PacifiCorp is thus enthusiastic to continue working with Henwood and other parties to ensure that the CEM is successfully implemented. Initially, it will be put through a rigorous validation and testing process. It will then be ready to use to inform the Action Plan Path Analysis in the next IRP Planning Cycle.

Coal

Procurement of a New Coal Resource

A number of parties raised concerns with the consideration of a new coal resource in the IRP. CUB opined that any decision on a traditional coal plant will have an increasingly high prudency hurdle, due to the uncertainties regarding future emission regulations. CUB also suggests that fuel price volatility is easier to manage than carbon risk. These concerns were echoed by ODOE, which suggested additional analysis postulating shorter useful lives for any new pulverized coal plant. RNP repeated its past position that it cannot support any conventional coal procurement by PacifiCorp. UCE-SLC notes PacifiCorp's portfolio is already carbon-intensive, and recommends pursuing non-carbon intensive resources to meet load growth.

Response: PacifiCorp is committed to exploring all options that may lead to providing least-cost resources for the future. Because of its low fuel cost, coal-fired generation historically has been seen as a least-cost generation option. Coal-fired generation may be particularly advantageous for utilities acquiring resources in the Rocky Mountains because coal is an indigenous resource. These plants have proven to be some of the most economic base-load power producers in the country, and are consistently dispatched before most other generation options with the exception of hydro and nuclear facilities.

Due to the increasing emphasis on the long-term impacts of atmospheric emissions, the viability of a heavy dependence on coal-fired generation for electricity supply is being called into question. PacifiCorp has attempted to capture the effects of this uncertainty by modeling the possible impacts of future environmental legislation. The IRP base case assumptions currently reflect CAI and global warming outcomes suggesting coal may continue to be part of the United States fueling strategy. If base case environmental assumptions change due to factors such as federal legislation, state-specific legislation, different relative fuel economics or technologic shifts, the economic viability of coal-fired generation may change.

PacifiCorp believes it has adequately addressed the risk of future carbon constraints, based on our current understanding of these risks, by adding a carbon value to plant production in the base case portfolio analysis and running sensitivities on this parameter. Even with such carbon values, coal plants remain a low-cost option.

In summary, it would be imprudent for PacifiCorp to omit coal as one of the least-cost alternatives for further review in the IRP Action Plan. PacifiCorp has consistently stated that the procurement process, and not the IRP process, is the proper forum for making specific resource choices. The goal of the IRP process is to identify the need for a particular type of resource and model possible candidate resources to identify the least-cost portfolio with the lowest risk. As we have pointed out, this modeling includes potential impacts of pending environmental legislation based on our current data.

Integrated Gasification Combined Cycle (IGCC)

UCCS anticipates the rapid development of commercially viable IGCC technology. WRA commends PacifiCorp's improved IGCC evaluation over the 2003 IRP, and advocates using IGCC technology if pursuing coal. WRA also provided several technical comments to improve the cost analysis. SC-WRA shared its legal opinion that the Utah Department of Air Quality should use an IGCC technology as the Best Available Control Technology (BACT) in any coal plant siting proceeding. CUB stated that IGCC is the only reasonable coal option to consider. RNP and UCE-SLC both reinforced this view, encouraging continued study of the IGCC option. OPUC suggested a stronger look at CO_2 capture and sequestration options in the context of IGCC study. UPSC asked for discussion on the most recent developments underway to commercialize IGCC technology.

Response: PacifiCorp provided an IGCC technology update at the November 10, 2004 Public Input Meeting. At this meeting, and in the IRP document (Chapter 6), PacifiCorp indicated its intention of evaluating IGCC as a potential option for the next plant procurement, and discussed revised technology assumptions, recent commercialization initiatives, and issues surrounding IGCC implementation. Subsequent to distribution of the IRP draft to the public, PacifiCorp also created and tested a stress portfolio that assumed early IGCC commercial viability sufficient to enable procurement by FY 2012. The IGCC resource was also modeled using updated technology cost and operational assumptions (a “7FB” configuration with a spare gasifier for increased availability). Chapters 7 and 8 provide the portfolio description and analysis details, respectively.

Regarding IGCC as a BACT technology, PacifiCorp is aware of the controversy surrounding consideration of IGCC as for coal-fired electrical generating units. However, this determination is made by appropriate regulatory authorities, not by PacifiCorp, and is thus not germane to the IRP.

PacifiCorp is carefully following the development of IGCC technology and recent developments that point to the commercial viability of this technology for future coal-fired plants. Currently, the technology has a series of challenges including cost, technical, operational, and fuel limitations that PacifiCorp constantly assesses as the technology improves to ensure that IGCC is fairly evaluated as a technology choice in the IRP.

Demand Side Management

Earlier/More Aggressive DSM Implementation

SWEEP comments on the proposed DSM programs were generally supportive, requesting further details on program specifics and costs. SWEEP also suggests acquiring DSM steadily and starting earlier. Several other parties encouraged consideration of more aggressive DSM efforts in the IRP. UAE stated insufficient attention was given to programs to address growth in peak energy usage. MWC urged the Company to be more aggressive. The UDPU encouraged more aggressive Class 1 and Class 2 DSM.

Response: Through Class 1 and Class 2 DSM efforts, this plan will reduce the peak load by 500 MW over the planning horizon. This consists of 177 MW of Class 1 programs and a Class 2 base case of 257 MWa (with a peak effect of 323 MW). In addition, the Action Plan seeks additional Class 2 results through RFP's. PacifiCorp believes that this effort is quite aggressive.

Additional program details including projected budgets by year, state, and program are included in Appendix C. Consistent with supply side PPA's, DSM programs that operate through a 3rd party vendor contract terminate at the end of the contract period. No assumption is made on a base case level whether the program continues or not. That will be a new economic decision at the time contract extension or renewal is considered. The base load forecast includes savings from these ongoing DSM programs through program budgets, as well as any long-term effects.

The dates for new Class 1 DSM programs in the Preferred Portfolio were chosen in order to defer supply side resources that would otherwise have been needed by FY 2009. In order to have the Class 1 programs fully operational by summer 2008, the Company will be issuing RFPs in CY 2005. Instead of selecting an arbitrary ramping schedule, the year of full implementation was modeled. As responses to a Class 1 RFP develop, they will be evaluated for cost effectiveness.

Programs which address growth in peak energy use are most valuable to PacifiCorp's system planning. They have the potential to delay the need for new capacity additions in the system. To address these growing needs PacifiCorp currently has several DSM efforts targeted at the east area summer peak:

<u>Class 1</u>

1) Cool Keeper, a residential and small commercial central electric air conditioner load control program, is currently built to 33 MW and is on schedule to have 90 MW of load reduction capability by FY 2007 assuming a 30% participation rate of residential customers with central electric air conditioners.
2) Electric City is a commercial/industrial lighting load control program newly under contract and scheduled to build to 27MW of load control.
3) The IRP Preferred Portfolio calls for additional load control programs totaling 177 MW by FY 2015.

<u>Class 2</u>

Most energy efficiency programs contribute to reducing peak loads. A listing of all programs currently in operation can be found in Appendix C. In particular, the Cool Cash program provides an incentive for efficient air conditioner decisions and the newly contracted Residential New Construction incentives program focuses on peak loads as well.

PacifiCorp is working on a plan to aggressively pursue 200 MWa of additional Class 2 DSM. The actual location, timing and costs of these new resources will be determined through the RFP process. Once achieved, a total of 450 MWa of Class 2 DSM will be implemented as a result of PacifiCorp's January 2003 and 2004 IRP planning processes.

<u>Class 3</u>

PacifiCorp operates an Energy Exchange each summer for larger commercial and industrial customers. Hourly prices are offered to customers to curtail load on days that are short or market prices are expected to be high.

Class 4
In conjunction with the Utah Energy Office, PacifiCorp participates in Power Forward. This is a "stop light" public appeal program that requests extra conservation efforts through media appeals on high load days. This program has seen measurable results.

DSM to Defer Resources
UCCS indicates that since DSM deferred resources in the Preferred Portfolio, the change in the load and resource balance should be reflected in all portfolios as it could change the rankings of the deterministic runs.

Response: After the Preferred Supply Side Portfolio was selected from among the candidate portfolios, cost effective Class 1 DSM programs were added to the portfolio to evaluate potential savings in system costs. The CEM tool was used to select the most cost effective Class 1 programs and the installation dates were guided by their potential for delaying resources within the portfolio. A resource was deferred if the addition of a DSM program kept the system planning margin at or above 15%.

The impact of Class 1 additions did alter the load and resource balance for the portfolio but would have a consistent impact across all candidate portfolios. All portfolio PVRRs would decrease with the Class 1 programs in a similar way since the overall system need was reduced in FY 2009 and FY 2014. Since the selection of the Preferred Supply Side portfolio was based upon portfolio performance in the deterministic, stochastic, as well as scenario model runs and the addition of Class 1 programs would similarly impact every portfolio through each modeling phase, PacifiCorp decided no additional portfolio modeling was required.

General
OPUC questioned the conclusion that benefits of Class 3 DSM are "short-term and tactical." WRA generally supports the DSM analytical framework. ODOE suggests a comparison between PacifiCorp's program levels and those proposed in the Northwest Power Planning Council's draft plan.

Response: PacifiCorp's Class 3 assessment is based on our program experience. PacifiCorp has two types of Class 3 programs, real-time demand response and tiered rate structures.

The C&I demand response program Energy Exchange, sees days when there is a response to a given price, while other days there is no response from any of the customers to the same level of price. This is not the characteristic of a long-term resource; therefore, at this time PacifiCorp cannot rely on planning for these types of programs as a long term resource. As PacifiCorp continues to gain more experience, and as customer response becomes predictable, this assessment could change.

Tiered rate structures, although intended to have significant impact on customer usage, have not yet produced these results. In the June 24, 2004 technical workshop on the load forecast, it was shown that the tiered rate structure has limited impact on residential A/C use. A large change in price is needed to affect the incremental A/C premium people are willing to pay. Current effects from tiered rate structures are included in the load forecast and updated with each new forecast as described within Appendix I. PacifiCorp has found that the price of electricity has little influence on the use of electricity.

ODOE requested a comparison between PacifiCorp's plan for DSM programs and the conservation plans of the Northwest Power and Conservation Council's (NWPCC) latest plan. The NWPCC issued their Draft 5th Power Plan in November which estimates 2,800 MWa of cost-effective conservation potential within the Pacific Northwest (Oregon, Washington, Idaho, and Western Montana) by CY 2025. To make this figure comparable to PacifiCorp's planning period from FY 2006 to FY 2015, their estimates for system load and conservation savings in 2025 were linearly extrapolated back to FY 2015 based on CY 2000 load of 20,080 MWa and the assumption that conservation programs begin in 2005. As a result, in FY 2015, their load forecast is approximately 23,100 MWa and conservation potential is 1,333 MWa or 6% of forecasted load.

Keeping in mind that PacifiCorp's service territory does not completely overlap with the Council's planning footprint, and therefore does not contain truly comparable demand patterns, 6% of PacifiCorp's FY 2015 system wide average load forecast equates to 370 MWa of additional DSM. In the 2004 IRP, the Action Plan calls for continuing to acquire the base Class 2 DSM amount of 250 MWa, which is included in the base load forecast for the IRP, and acquire up to an additional 200 MWa of cost effective programs through the RFP process. In order to achieve this additional 200 MWa, the Energy Trust of Oregon programs, targeted towards PacifiCorp's customers, will contribute to the total. The base 250 MWa is actively being pursued and has either recently started or will be starting over the next few years. In addition to the Class 2 programs, the Preferred Portfolio includes 177 MW of new Class 1 programs over and above the base case of 125 MW Class 1 resources.

The NWPCC target for conservation is aggressive but potentially achievable if enough cost effective DSM can be procured, and PacifiCorp's plans for continued DSM through FY 2015 are in line with these estimates. Additional details on new and existing programs are provided in Appendix C.

Need for New Sources of Supply

Load

SWEEP comments that the Utah load growth forecast may be too high. UCCS also comments that the load forecast for Utah appears optimistic given current economic conditions and new load control and rate design programs now in place. UPSC comments that the omission of historical load growth rates for certain years attributable to recession and a terrorist event is inappropriate. UPSC calls for more detailed information on both coincident and non-coincident peak and energy load forecasts.

Response: PacifiCorp believes that the load forecast for Utah is reasonable. Utah energy use is projected to grow at the same rate as the historical rate. The load from 1991 to 2003 grew at 3.5% per year while the forecasted rate of growth is also 3.5% per year from FY 2006 through FY 2015. The summer peak demand is projected to grow at a rate less than the historical rate. The peak demand from 1991 through 2003 grew at 6.2% per year while the forecasted rate of growth from 2006 through 2015 is at 4.6% per year. The projected growth in energy and peak demand is reasonable due to the assumed economic recovery during the early time period of the planning horizon and the continued adoption of air conditioning throughout the planning horizon. Details of the historical and forecast information for energy load, coincident peak demand, and non-coincident peak demand has been included in Appendix I.

The historical growth rates have been re-stated in Chapter 3 to include the growth rates for the time period associated with the recession and terrorist events (2001 – 2003). These growth rates are provided as a comparison against the IRP load forecast. Including this recession period has a definite impact on the historical growth rate. For example, energy grew at 4.3% per year from 1991 through 2000 as compared to the 3.5% growth rate from 1991 through 2000. Also, coincident peak demand grew at 7.4% per year from 1991 to 2000, as compared to the 6.2% coincident peak demand growth rate in the historical period from 1991 through 2003.

Existing Resources

MWC and UAE comment that the treatment of future procurement of DSM, wind, and Front Office Transactions as an "existing" resource for purpose of building portfolios is confusing and tends to understate the need for new sources of supply. WRA suggests discussion of how the potential renewal of existing contracts would affect the need for new supply. UPSC asked for documentation regarding thermal plant retirement dates.

Response: Chapter 3 has been updated to include a detailed discussion of existing and planned resources, including specific criteria and rationale for each. Chapter 3 and Appendix C include a unit retirement schedule, and Chapter 3 includes a discussion on thermal plant life.

Many factors contribute to the need for new resources over the next ten years, including load growth in PacifiCorp's existing customer base, load growth resulting from the addition of new customers, and making up lost capacity due to contract expirations, hydro relicensing and aging plants. Figure 9.1 in Chapter 9 provides an overview of how each of these components contributes to the 2,800 MW deficit position. As indicated by Figure 9.1, the expiration of contracts is responsible, in part, for deficits reflected in the IRP load and resource balance.

Portfolio Analysis

CO_2 Scenario Analysis

Several parties, including CUB, RNP, WRA and UCE-SLC, commend the IRP for the acknowledgement and analysis of CO_2 regulation risks. UPSC called for expanded discussion of how CO_2 assumptions were developed and used in the study. UDPU called for a reexamination of the CO_2 adder methodology as the policy issue evolves. WRA suggests incorporating escalating CO_2 risk in future scenario analyses.

Response: An expanded discussion on how CO_2 assumptions were developed and used in the 2004 IRP was added to Chapter 5. 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 credit 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 $8/ton CO_2 (2004$) 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 from thereafter. If total fleet 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

PacifiCorp plans to reexamine all assumptions used to develop the base case view of potential carbon regulations. WRA's suggestion to incorporate escalating CO_2 risk in future scenario analyses is currently not a part of PacifiCorp's corporate strategy for planning but may be considered as future regulations and impacts unfold.

Diversified Portfolio

UCCS states that the Preferred Portfolio appears to be weighted too heavily toward natural gas and short to medium-term market resources, and that an equal mix of gas and coal should be considered "diversified". UPSC would like PacifiCorp to provide a definition of a Diversified Portfolio.

Response: PacifiCorp defines a diversified portfolio as having a mix of new resource types that helps to balance the current system resource mix. This definition has been added to the Chapter 7 discussion on Reference Portfolio A. In evaluating portfolios, PacifiCorp does not apply a threshold to determine if a portfolio is considered diversified. Rather, the focus is on how new resource mixes impact expected PVRR and the overall portfolio's risk profile as determined by the various risk measures used for portfolio analysis. The IRP risk analysis process accounts for the risks unique to each fuel type: price escalation and volatility in the case of natural gas, and costs associated with potential CO_2 reduction/sequestration requirements in the case of coal. PacifiCorp believes that it has applied a balanced approach to constructing portfolios and evaluating these fuel type risks consistent with the long term goal of portfolio diversification.

Regarding UCCS's point that the Preferred Portfolio is also too heavily weighted with short-to-medium term market resources, PacifiCorp arrived at an appropriate level of 1,200 MW for its Front Office Transaction resources based on institutional experience and a review of historical operational data and existing transmission constraints. The end result is a Preferred Portfolio that meets the IRP objective of being the lowest-cost, risk-informed resource mix, and also has the added benefit of materially contributing to fleet-wide diversification.

General

UAE comments that due to small PVRR differences, all 17 portfolios should be part of the risk phase of analysis. UPSC also questions whether the small PVRR differences among the best performing portfolios are material.

Response: To provide a rigorous risk analysis and keep the portfolio group to a manageable size, certain portfolios were eliminated from the risk analysis group in accordance with the documented selection criteria. The Chapter 8 discussion on candidate portfolio performance has been amended with a more detailed discussion on why certain portfolios were not subjected to risk analysis. PacifiCorp selected portfolios for risk analysis that were low-cost and reflected a representative set of resource types displaying the key risk factors. For example, IGCC and pulverized coal technologies have effectively identical fuel price volatility risks. Therefore, including the IGCC portfolios in the risk analysis group is not necessary given that the pulverized coal portfolios adequately represent the risk profile for baseload coal resources. In summary, the selected risk analysis portfolios adequately capture the quantifiable risks associated with the various resource combinations evaluated.

Wind

20% Planning Contribution

Many parties commended PacifiCorp for its evaluation of the capacity contribution attributed to wind resources in the plan. WRA deems the ELCC methodology for arriving at the wind capacity factor to be appropriate, and asks the Company to do a revised ELCC analysis using the results of the 2003-B Wind RFP. UDPU, however, questioned whether the 20% assumption was robust enough, given that specific wind sites will have varying fuel characteristics. MWC echoed this concern.

Response: PacifiCorp agrees that the results of the capacity contribution study are highly dependent upon the assumptions used to complete the study. One of the most significant assumptions was the operating characteristics of new wind resource additions. PacifiCorp plans to modify this study with new information as it becomes available regarding potential resource performance by location and any new renewable resource acquisitions resulting from RFP 2003-B.

1,400 MW Assumption

Many parties commended PacifiCorp for its continuing efforts to procure 1,400 MW of wind energy. RNP supports this wind target as an interim goal. ODOE comments that the 2004 IRP should consider a much higher supply curve for wind, rather than the static 1,400 MW target that was established in the 2003 IRP, and speculates that up to 6,000 MWa of wind may be viable for PacifiCorp. WRA also suggests a higher supply curve for wind in the later years of the study horizon, and suggests proactive steps to identify and address uncertainties with penetration of wind beyond 1,400 MW.

Response: PacifiCorp’s conclusion that it is reasonable to include 1,400 MW of new renewable generation in the base case assumption for the 2004 IRP was supported by the most current data available, and subsequent modeling with the Capacity Expansion Model. A renewable generation supply curve was derived from responses to the 2003-B RFP. PacifiCorp was careful to aggregate the data in order to protect against any possible identification of specific bids that would violate confidentiality agreements with bidding parties. For that reason, and because the data were roughly equally split between eastern and western control areas, PacifiCorp declined to produce separate east and west-side supply curves.

The request to expand the supply curve implies the need for additional new renewable generation availability and cost data throughout PacifiCorp's service territory. Given that the supply curve becomes clearly uneconomic at the high end, we have not studied the significance of extending the curve further at this time. PacifiCorp has included all the information gathered through responses to the 2003-B RFP in the supply curve, and any attempt on PacifiCorp's part to expand the curve would be based on extrapolation or estimation.

General

WRA indicated that is was important that the Company take proactive steps now to identify and address uncertainties associated with wind at penetration levels up to and beyond the currently proposed 1,400 MW. WRA also asked the Company to perform a revised integration cost analysis on its system using the results of the 2003-B Wind RFP. MWC questions how additional data from numerous diverse sites would impact imbalance costs.

Response: Transmission, integration cost, capacity contribution, cost effectiveness, availability and many other issues have all been raised as areas which need further analysis before significant amounts of new wind generation are added to the system. As more renewable generation, particularly wind, is added to the system, PacifiCorp acknowledges that these areas will require much more in-depth analysis. Although more work needs to be done, so far PacifiCorp has taken proactive steps by participating in regional and national wind forums and closely following legislation related to renewable generation. Improvements to day-ahead forecasts, wind integration valuation, and capacity contribution assumptions will also be considered in preparation for the potential for additional wind on the system.

Once additional resources are procured in response to the 2003-B RFP, a revised integration cost analysis will be performed to value the costs of system imbalance and incremental reserves due to hourly-varying wind resources.

Additional data from numerous diverse sites will likely impact imbalance costs. The extent to which a non-dispatchable resource's output matches the load center demand, impacts imbalance costs. It would be difficult to estimate how additional resources would perform relative to demand and location without having good site data and running the system dispatch model. As more data is available, these assumptions will be updated.

Standards and Guidelines

Several parties commented on whether the 2004 IRP is in full compliance with States' IRP Standards and Guidelines. Most of the comments focus on Utah's guidelines, some of which are paraphrased here for purposes of organizing the comments and PacifiCorp's response.

1. *The IRP must be conducted in an open, public process and give interested parties a meaningful opportunity to participate and provide comments.*

MWC, UDPU and UAE comment that lacking access to the draft appendices that accompany this IRP was an impediment to their ability to provide informed comments on the draft report. UCCS commends the Company on the public process and encourages the continued use of the video link to facilitate participation by all interested parties. UCE-SLC suggests deliberative polling be used as a means for broadening the public process.

Response: PacifiCorp has devoted serious effort and attention to involve the interested public in the development of the IRP. The public input process is described in Appendix B. During the November 10, 2004 IRP Public Input Meeting, PacifiCorp indicated that, although all the Appendices were not available to be distributed with the draft document, the latest draft appendices would be e-mailed to any party requesting the information if they felt it necessary to provide comments. A draft copy of the Appendices was sent to all IRP public input participants on December 16.

2. *The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.*

UAE questions whether DSM was given consistent treatment with other alternatives, because of the methodology used in the IRP. UDPU questions the validity of the Class 2 DSM cost effectiveness criterion, suggesting a costs-per-MWH of retail sales benchmark be used, instead of PVRR.

Response: PacifiCorp believes both Class 1 and 2 DSM programs are evaluated on a fair and consistent basis with supply side resources within this IRP. In order to fairly evaluate any resource for inclusion in the final plan, current information on capacity, operating characteristics, location, and cost of the resource is needed. Since this information is not currently known for Class 2 programs, the decrement analysis was used to provide an annual stream of $/MWh rates representing the reduction in production costs for the amount of energy savings produced by each program. PacifiCorp has found that the best information regarding size, end use, location, and cost for potential Class 2 programs is found in responses to RFPs; therefore, the decrement values will be used to evaluate the cost-effectiveness of proposed programs.

Current cost and savings details were available for several Class 1 programs, therefore they were fairly considered by allowing the CEM tool to select the most cost-effective programs out of a selection of eight choices. Once added to the Preferred Supply Side portfolio, the overall PVRR decreased, indicating its positive impact on the final portfolio.

Consistency in valuation of all resource types was also considered. All resources were evaluated within the same modeling representation for system loads, existing resources, and market conditions. Although each type was not evaluated in the same way, they were considered in a manner most appropriate for their resource type.

UDPU questioned the validity of using PVRR for Class 2 cost-effectiveness criteria. PacifiCorp would like to clarify its use of the results of the decrement analysis and explain the validity of the analysis. The analysis provided annual $/MWh values for avoided system production costs for eight program shapes, representing a broad range of potential DSM offerings which may be submitted in response to PacifiCorp's DSM RFP. PacifiCorp tests the cost-effectiveness of each potential DSM program with the commission mandated cost effectiveness tests; TRC, UTC, RIM, and PCT, using forward market prices for the utility avoided cost. In addition, PacifiCorp runs the test with the annual decrement price streams in place of the avoided market prices for the load factor most similar to the proposed program end use shape. The decrement values alone are not used to judge program cost effectiveness; rather, they are used to create an additional set of cost benefit ratios with the avoided system production costs replacing avoided market costs. PacifiCorp is open to further development and refinement of the decrement approach to DSM valuation.

3. *The IRP must include an assessment of all technically feasible generating technologies.*

UDPU requests an explanation for why nuclear generation was not evaluated in the IRP, or whether it was considered and rejected. UAE and MWC argue that CHP and DSM options were not fully assessed, and asserts that inadequate attention was given to other options, including IGCC, CFB and IC. ODOE and WRA argue a higher wind supply curve should have been assessed.

Response: PacifiCorp believes that all technically feasible technologies were evaluated in this IRP. Chapter 6 contains a discussion of all such technologies which includes gas, coal, DSM, CHP, hydroelectric generation, and several other technologies. The modeling results of several of these technologies, including CHP and DSM, are contained in Chapter 8.

PacifiCorp has added in Chapter 6 a discussion of all resources, including nuclear generation, circulating fluidized bed (CFB), and dual fuel IGCC.

4. *The IRP will include analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric services … the IRP will also include a narrative describing how current rate design is consistent with the Company's IRP goals and how changes in rate design might facilitate IRP objectives.*

The UPSC and UDPU refer to these Utah guidelines. UDPU requests discussion on the observed and projected effects of moving to inverted block rates on electricity consumption in Utah. UPSC asks for a discussion on rate design consistency with IRP goals.

Response: Appendix I provides details concerning PacifiCorp's economic and demographic sector methodology, including recent demand response and elasticity studies for the residential customers and an analysis of inverted block rate design.

A discussion on how current rate design is consistent with IRP goals, along with PacifiCorp's efforts to evaluate the impacts of moving to more steeply inverted block rates, is included in the Class 3 DSM section of Chapter 6 as well as Appendix I. PacifiCorp indicates in Chapter 6 that current rate design is consistent with the IRP goal of providing low-cost, reliable electricity service to customers, and that it offers a variety of rates that provide cost signals to reduce or shift load.

5. *The IRP requires load forecasts by jurisdiction and by general class and differentiation of energy and capacity requirements. The IRP also will rely on a range of load forecasts.*

UPSC requests a complete documentation of load forecasts to demonstrate compliance of these requirements. UCCS states the IRP is based upon a single point forecast and therefore lacks compliance with this guideline.

Response: PacifiCorp has updated Chapter 3 and Appendix I to include the load forecast growth rates and 2003 GWh sales by jurisdiction and customer class, as well as historical and forecasted energy load and peak demand.

PacifiCorp has complied with the requirement to rely on a range of load forecasts in the stochastic analysis. As described in Appendix G, the base load forecast is "shocked" through assumptions about the two-factor mean reversion process. Through this analysis 100 alternative load forecasts are evaluated in conjunction with varying forecasts of the price of natural gas, the electric market price, hydroelectric availability, and thermal outage rates. This stochastic analysis and the associated variation in the load forecast play a major role in the determination of the Preferred Portfolio for this IRP.

6. *The IRP will define least cost based on total resource cost, i.e., costs incurred by the utility and the ratepayer, and will also define utility cost, and will choose the least cost portfolio by minimizing total resource cost.*

UPSC asks whether PVRR is utility cost or total resource cost and to explain how the IRP complies with this guideline.

Response: A discussion on total resource cost and PVRR has been added to Chapter 5.

7. *The IRP process will result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.*

UCCS is not persuaded that the Preferred Portfolio is "optimal" and consistent with the long-run public interest. Since a modeling tool with resource addition logic was not used to develop portfolios, UCCS is concerned the Preferred Portfolio may be suboptimal. UCCS is also concerned that natural gas prices appear unreasonably low, and the coal capital cost assumptions appear high, skewing the analysis in favor of natural gas-fired generation in the Preferred Portfolio. The risk analysis is also deficient, the UCCS believes, because the Front Office Transactions were not subjected to stochastic or scenario risk analysis, and the possibility of a structural shift in the natural gas market or a recurrence of wholesale electricity market abuse or malfunction were scenarios not adequately addressed. The cumulative effect of the above concerns leads UCCS to believe that the Preferred Portfolio is weighted too heavily toward natural gas and market purchases, and is not the optimal set of resources given the expected combination of costs, risks and uncertainty.

Response: PacifiCorp believes that it has applied a rigorous and balanced portfolio evaluation process for this IRP, and continues to augment the process with new information as it becomes available. Despite the limited use of the CEM in this IRP cycle, PacifiCorp confirmed that the CEM resource selection algorithm produces results similar to the manual portfolio build process, providing confidence that the optimal supply-side and Preferred Portfolios successfully converge to the lowest-cost, risk-informed solutions. (See the response in the “Resource Addition Logic” section of this appendix for more details.)

PacifiCorp’s risk analysis framework of stochastic and scenario risk simulations adequately addresses the risk factors for coal, natural gas, and market transactions. For example, the Front Office transaction resources included in the risk analysis portfolios are subjected to risk impacts by virtue of the stochastic distribution of market conditions against which they are dispatched in the stochastic simulations. In addition, the portfolio evaluation process has been responsive to recent market developments as evidenced by new high gas price scenario risk simulations that use PacifiCorp’s latest gas price forecasts (See the response in the “Gas Price Forecast” section.) PacifiCorp’s technology cost information is also based on the latest information, as well as recent company experience. When expressed on a comparable basis, the costs are consistent other cost analysis study results and projects applicable to PacifiCorp’s region.

Regarding the point that PacifiCorp did not adequately address potential wholesale market malfunctions, we believe that the risks for such malfunctions have been diligently examined and thoroughly discussed in the IRP document. The discussion of western market conditions in Chapter 1 and Appendix A were augmented to further address UCCS concerns.

8. *The IRP will include an evaluation of the financial, competitive, reliability and operational risks associated with various resource options.*

UCCS is concerned that the risks associated with natural gas prices and Front Office Transactions were given inadequate attention in the IRP.

Response: Please note that Appendix C includes a discussion of the risk analysis performed on the Front Office Transactions. The Company has met the standards and guidelines by performing stochastic portfolio analyses on this dispatchable resource. Please refer to the response under “Gas Price Forecast” earlier in this appendix for a discussion of how gas risk was handled in the IRP.

9. *The Company will identify who should bear the risk, the ratepayer or the stockholder.*

UDPU requests a discussion of this issue in the IRP report. UPSC would like clarification on rate payer and shareholder risk summary. UCCS states that when risk is not well analyzed and tradeoffs not fully identified, shareholders should bear the risk of poor outcomes.

Response: PacifiCorp addresses ratepayer/shareholder risk in Chapter 3 of the document and this discussion is applicable to all portfolios.

10. *The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years.*

UDPU compares the level of detail in the draft IRP to the 2003 Action Plan and deems it “substantially inferior” and encourages the use of target delivery dates specific to the first two years of the plan. UCCS also seeks more detail in the action plan, and recommends itemizing the actions that will be taken to implement the chosen portfolio.

Response: The Action Plan summary table (Table 9.2) combines both the findings of need and the implementation actions from the 2003 IRP into one table. In response to the comments, PacifiCorp has modified the Action Plan Implementation section of Chapter 9 to include timelines associated with procuring specific action items. This section has also been modified to include actions PacifiCorp is planning to meet the targets outlined in the summary table.

11. *The IRP will include 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*.

UCCS, UPSC, UDPU and UAE all refer to this guideline in comments, calls for discussion, and suggests it be an element in the Action Plan.

Response: PacifiCorp included an Action Plan Path Analysis in Chapter 9 of the 2004 IRP. As was indicated in Chapter 9, the majority of the items in the Action Plan will be acted upon prior to the next IRP planning cycle. Therefore, since the time frame for these decisions is short, numerous or significant changes affecting the outcomes are not anticipated. Unless the rules set by the regulatory bodies influencing resource choice decisions change, PacifiCorp would anticipate that the 'decision mechanism' would adhere to the least cost / lowest risk dictum given the conditions prevalent at the 'specific point in time' that such decisions would be made.

During the public input process, CCS recommended that PacifiCorp use the Capacity Expansion Tool in the Action Plan Path Analysis. PacifiCorp has included this recommendation as an Action Item in the Action Plan. PacifiCorp will continue to work in a collaborative effort with public input meeting participants to improve this area in future IRPs.

12. *The IRP will take into account externalities associated with alternative resources.*

MWC and UAE note that environmental externalities were not expressly considered, except for projected costs for certain specified emission requirements. WCAC comments that the negative impacts of generation emissions on pulmonary health are inadequately weighed in the IRP.

Response: PacifiCorp believes it has taken a reasonable approach to the consideration of environmental externalities, in compliance with IRP standards and guidelines. Our method of quantifying expected future costs of air emissions was extensively reviewed with stakeholders during Public Input Meetings, and with PacifiCorp's Environmental Forum, consisting of external parties representing a range of stakeholder interests.

Specifically, PacifiCorp has included additional costs for environmental externalities through modeling emissions cap and trade programs. Within the IRP model, those resources with fewer emissions receive lower emissions costs than other more heavily polluting resources. These emissions values are also reflected in the total resource cost of each potential new resource in the supply side options table in Appendix C (C.27). This method of accounting for externalities is quantifiable and allows a direct comparison between portfolios.

While many resource alternatives can possibly introduce other environmental impacts beyond these specific air emissions, 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. As such, they can only be reasonably assessed on a project specific basis. PacifiCorp has reviewed the discussion of new supply alternatives and supplemented that discussion to point out the potential for other environmental impacts, where appropriate.

13. *The IRP will include an evaluation of the cost-effectiveness of the resource options from the perspective of the utility and the different classes of ratepayers.*

UPSC indicates that the revenue requirement calculation in the customer impact analysis is unclear.

Response: The methodology used for Customer Impact analysis during the 2003 IRP was discussed at some length, and it was decided a similar methodology be used for the 2004 IRP. It was requested that the retail rate used as a benchmark for the existing resources be shown with depreciation subtracted. As requested, depreciation was subtracted from retail revenue requirement to reflect retail rate less depreciation. The same retail rate less depreciation is used for each year of the analysis. Calculating a different depreciation amount each year would involve including capital additions and subtractions. In addition, it would involve predicting retail revenue for each year, which would involve a modeling analysis not performed in the context of the IRP. The retail rate on which the Customer Impact is based was offered as a "benchmark" to indicate the magnitude of impact of each portfolio based on cost, not as an accurate representation of our forecasted retail rate over time.

PARTIES WHO SUBMITTED WRITTEN COMMENTS

CUB – Citizens' Utility Board of Oregon
MWC – Mountain West Consulting
ODOE – Oregon Department of Energy
OPUC – Oregon Public Utility Commission staff
RNP – Renewable Northwest Project
SC-WRA – Sierra Club, Utah Chapter and Western Resource Advocates
SWEEP – Southwest Energy Efficiency Project
UAE – Utah Association of Energy Users
UCE-SLC – Utah Clean Energy and Salt Lake City
UCCS – Committee of Consumer Services State of Utah
UDPU – Utah Division of Public Utilities
UPSC – Utah Public Service Commission staff
WCAC – Wasatch Clean Air Coalition
WRA – Western Resource Advocates

APPENDIX M – PERFORMANCE ON 2003 IRP ACTION PLAN

INTRODUCTION

This Appendix summarizes the performance on the updated 2003 IRP Action Plan filed in October 2003.

PacifiCorp's original 2003 Integrated Resource Plan (IRP) was filed on January 24, 2003. This report supported PacifiCorp's objective of providing reliable and least cost electric service to all of its customers while minimizing the substantial risks inherent in the electric utility business. The January IRP report described prudent future actions to fulfill this objective based on the best information known at the time, and also called attention to the IRP as a continuous process rather than a one-time or occasional event.[36] The IRP was developed with considerable public involvement from customer interest groups, regulatory staff, regulators and other stakeholders. The IRP was submitted to all six States that regulate PacifiCorp's retail electric operations and was acknowledged in all States with IRP Standards and Guidelines requiring an acknowledgement process.

In October 2003, PacifiCorp filed an update to the 2003 IRP Action Plan that reflected ongoing long-term planning work and improvements to models, assumptions and processes. The update included a status report on each of the Action Plan items identified in the January 2003 IRP. In addition, changes to the Action Plan that were warranted by the new information were also highlighted in the update. Changes to inputs and assumptions included a revised load forecasting methodology resulting in an updated 20 year forecast, changes to coal plant development timelines, and an improved representation of transmission issues in our modeling, and market prices. PacifiCorp also outlined additional analysis that had been conducted including detailed model validation against actual system operations data and improvements in the synchronization of short-term operations and planning with long-term IRP planning efforts.

[36] The plan stated (pg. 152) that the IRP Action Plan "will be implemented as described…but is subject to change as new information becomes available or as circumstances change." Also, the plan stated that it is "PacifiCorp's intention to revisit and refresh the Action Plan no less frequently than annually."

UPDATE ON 2003 IRP ACTION PLAN

Table M.1 provides an overview of the updated 2003 IRP Action Plan. The 'STATUS/UPDATE' column summarizes specific progress or information updates to each action.

Table M.1 – Updated 2003 IRP Action Item Status

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS/UPDATE
Base Load - West by FY2007	1. Prepare detailed plans, including: an economic review and justification for building a base load CCCT in the West of the system, level of resources needed, and the procurement date. The review will address: • The merits, risks and benefits of negotiating alternative PPA agreements following the expiration of existing contracts in the West • The potential and options for negotiating additional capacity associated with the existing BPA contract.	The 2004 load resource balance and resulting West position shows that there is no need for a baseload resource by FY2007.
Base Load – East by FY2008	2. Procure a base load unit in the East of the system for operation by FY2008. Prepare detailed plans including a review and justification for building or buying the base load unit. Prepare detailed plans including a review and justification for building or buying the base load coal unit in the East of the system for FY2008. The review will include, but will not be limited to: • An economic review for selecting coal as the fuel • Alternative fuel options including natural gas • Emissions Impacts on the surrounding area • Other existing or partially developed sites • Alternative PPA agreements with appropriate credit worthy counter-parties	RFP 2003 A targeted to procure a base load unit in this timeframe. RFP resulted in the procurement of a 534 MW CCCT plant (Lake Side) located near Salt Lake City. PacifiCorp was granted a Certificate of Public Convenience and Necessity (CCN) by the Utah Public Service Commission on November 12, 2004.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS/UPDATE
Base Load East	3. Continue environmental permitting activity for Hunter 4 to ensure this base load plant option is available for implementation and operation in or after FY2009.[37]	Filed for NOI on May 8, 2003 with the Utah Division of Air Quality. Permit is pending.
Base Load	4. Procure a base load unit in the East of the system for operation in or after FY2009.[38] Prepare detailed plans including a review and justification for building or buying the base load coal unit in the East of the system. The review will include, but will not be limited to: • An economic review for selecting coal as the fuel • Alternative fuel options including natural gas • Emissions Impacts on the surrounding area • Other existing or partially developed sites • Alternative PPA agreements with appropriate credit worthy counter-parties	The timing and size of this resource need is being determined in the 2004 IRP (Preferred Portfolio)
DSM	5. Design and determine the cost effectiveness of the proposed Air Conditioning Load Control program in Utah. Launch and implement the Air Conditioning Load Control program as appropriate and in line with the findings.	Complete. Cool Keeper program launched in May, 2003. UT Schedule 114 was filed 4/9/03, and was effective 5/14/03. Program participation is ahead of budget.
DSM	6. Design and determine the cost effectiveness of the proposed refrigerator re-cycling program. Launch and implement the refrigerator re-cycling program as appropriate and in line with the findings.	Complete. See 'ya later Refrigerator program launched in June, 2003. UT Schedule 117 was filed 5/5/03 and was effective 6/16/03.

[37] This action item not in agreement with the Oregon Acknowledgement Order (Docket LC 31).
[38] This action item not in agreement with the Oregon Acknowledgement Order (Docket LC 31).

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS/UPDATE
DSM	7. Design and determine the cost effectiveness of the proposed efficient central air conditioner program. Launch and implement the efficient central air conditioner program as appropriate and in line with the findings.	Complete. Cool Cash program launched in May, 2003. UT Schedule 113 was filed 2/21/03 and was effective on 3/24/03.
DSM	8. Complete an evaluation of the available, realistic CHP sites and market size throughout the PacifiCorp territory.	Utah Complete. Participated in the Primen study for complete system market assessment. CHP assumptions have been updated and a stress case portfolio was analyzed in the 2004 IRP.
DSM	9. Implement and operate the specific DSM programs in the D-P40 decrement that was included DPI. This will build 150 MWa DSM between 2004 and 2014.	Complete. Programs are continuing operation.
DSM	10. Conduct an Economic and Market Potential study throughout the PacifiCorp Service territory to determine the magnitude of the DSM opportunities available to PacifiCorp, including Oregon Class 1, 3 and 4 DSM resources.	Complete. The market opportunity was measured through the 2003 DSM RFP process. No other market potential study will be conducted.
DSM	11. Design a “bundle” of cost effective DSM programs that build to an additional 300 MWa between 2004 and 2014 in line with the decrement options reviewed in the IRP.	Ongoing. Two cost effective Class 2 programs resulted from the 2003 DSM RFP: residential new construction incentives and commercial re-commissioning.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS/UPDATE
DSM	12. Prepare, issue and implement a Request For Proposals (RFP) for 100 MWa of Class 2 DSM for implementation commencing early 2004 as part of the "bundle' of options in action item 11.	Complete. DSM RFP 2003 was issued June 26, 2003. Responses received August 18, 2003. Two new Class 2 programs (See # 11) were selected to be initially launched in Utah and one new Class 1 program was selected.
DSM	13. Determine revised DSM targets for the period 2004 to 2014 based on the results of action items 10, 11 and 12.	Revised targets have been included in the 2004 IRP.
DSM	14. Evaluate and implement as appropriate the irrigation load control program in Idaho for 2004.	Complete. ID Schedule 72 issued 1/31/03, effective 3/17/03. Pricing and curtailment for summer '03 complete. The program was also implemented in summer 2004.
Flexible Resources (Daily Dispatchable) - FY2006	15. Procure flexible resources (daily dispatchable) for the East side of the system for operation in FY2006. Develop detailed plans and proposals, including the timeline for delivery, for flexible resources required for the East side of PacifiCorp's system for FY2006.	Complete. RFP 2003 A targeted to procure flexible resources in the East. On March 5, 2004 PacifiCorp was awarded a Certificate of Convenience and Necessity by the Utah Public Service Commission (UPSC) to begin construction of Currant Creek, a new 525 megawatt (MW) gas-fired plant located 75 miles south of Salt Lake City, Utah.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS/UPDATE
Flexible Resources	16. Review the West Valley plant performance and requirement and negotiate the West Valley plant terms and conditions in line with the existing lease contract arrangements.	PacifiCorp will retain for at least three years the West Valley lease. The decision results from a Request for Proposals issued by PacifiCorp July 19, 2004, to see if there were alternatives superior to the West Valley Plant resource. PacifiCorp's decision will continue the lease until at least May 31, 2008.
Renewables	17. Evaluate expansion options for PacifiCorp's Blundell Geothermal plant and implement expansion if appropriate and cost effective.	Consideration of plant expansion has been deferred due to unanswered concerns about the steam resource.
Renewables	18. Prepare, issue and implement an RFP for wind generation on the West of the system in line with the proposed procurement pattern: • 100 MW – FY2006 • 200 MW – FY2008 • 200 MW – FY2010 Move up acquisition dates if RFP process reveals it is economic to do so.	RFP 2003 B targeted to procure renewables for the system. Short List announced October 20, 2004. Negotiations are underway with short-listed bidders. (Note: Items 18, 19, and 20 were addressed in a single RFP.)

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS/UPDATE
Renewables	19. Prepare, issue and implement an RFP for wind generation on the East of the system in line with the proposed procurement pattern: • 200 MW – FY2007 • 200 MW – FY2009 • 200 MW – FY2011 Move up acquisition dates if RFP process reveals it is economic to do so.	See status of Action Item 18.
Renewables	20. Prepare, issue and implement an RFP for renewable generation options (i.e. geothermal, solar, fuel cells) which could be implemented in addition to, or as an alternative to, the proposed wind build pattern modeled in DP1 (Action Items 18 and 19).	See status of Action Item 18.
Shaped Products	21. Determine the strategy and negotiate, as appropriate, asset based shaped product contracts to fill: • The super-peaking needs in the East of the system for 2004/05/06/07 • Thermal asset based contracts in support of the capacity requirements to achieve the appropriate planning margin established through Implementation Action 24 on both the East and West of the system. • Thermal asset based contracts (25 MW) to support the addition of profiled wind in the East and West of the system.	RFP 2003 A was targeted to procure super-peaking needs for the designated timeframe. No cost effective bids were received in this category.
Strategy and Policy	22. Determine the long term IRP model(s) including a review of options for using optimization logic for future IRP's.	The Capacity Expansion Model, developed by Henwood, has been partially validated and used for (1) deriving a test portfolio for comparison with manually-constructed portfolios, (2) Class 1 DSM program analysis, and (3) validation of 1,400 MW wind assumption.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS/UPDATE
Strategy and Policy	23. Agree to any changes to Standards and Guidelines that may impact the implementation of the IRP Action Plan	PacifiCorp is currently participating in open dockets in Oregon and Washington to review Standards & Guidelines. Will continue to be proactive about participating in state discussions as they materialize.
Strategy and Policy	24. Determine the Planning Margin PacifiCorp will adopt if different from the 15% planning margin adopted in this IRP. The analysis for this will include loss of load probability studies.	The Planning Margin Study was completed and documented in Appendix N of IRP report. The study resulted in no change from the 15% planning margin that was adopted in the 2003 IRP.
Transmission	25. Detail and commission selected transmission power system analysis studies to support the implementation of the IRP Action Plan. The studies will provide greater detail on transmission costs associated with all the portfolio additions.	Interconnection and system impact studies were requested in line with resources being analyzed in RFP 2003 A and RFP 2003 B.
Transmission	26. Prepare detailed plans including an economic review and justification and apply for necessary transmission upgrades to support asset additions.	See status of Action Item 15.
Transmission	27. Prepare detailed plans including an economic review and justification to implement the "Wasatch Front Triangle" transmission upgrades.	One of the transmission upgrade projects, the addition of a 345 KV line from Mona, was completed.

ADDITION TYPE	IMPLEMENTATION ACTIONS	STATUS/UPDATE
Transmission	28. Review options for firming up the IRP non-firm transmission requirement.	Request for firm transmission service into Utah is currently under study by Idaho Power Company.
DSM	29. For the next IRP or Action Plan brought forward for the Commission's acknowledgment, assess Class 1, Class 3 and Class 4 demand-side management resources in Oregon, include in the portfolios those resources that are least cost, and include in the load forecast the likely impacts from implementation of DSM programs.	Class 1 was evaluated by modeling various levels of potential load control in the automated resource addition logic in the 2004 IRP planning process. Class 3 and Class 4 programs do not produce predictable results for use in long-term planning.
DSM	30. If the Company's demand response assessment due year-end indicates new voluntary demand response pilots or programs are cost-effective now or build capability for the future, bring them forward by March 31, 2004, for the Commission's consideration with a proposed effective date of May 1, 2004.	Demand response assessment filed in January 2004 with the OPUC. Pilot large customer interruptible tariff was filed for winter, 2004/05.
Renewables	31. Perform studies on the capacity value for wind resources and determine the appropriate level for use in the next IRP or Action Plan requiring Commission action.	PacifiCorp conducted a capacity contribution study for wind resources; the results and conclusions are documented in Appendix J of this report.

APPENDIX N – PLANNING MARGIN STUDY

INTRODUCTION

Electric utility resource planning incorporates many assumptions which impact forecasts of future energy demands and the resulting amount of generation resources necessary to meet that demand. In PacifiCorp's January 2003 Integrated Resource Plan (IRP), the company assumed a 15% planning margin as the amount of resources above future estimated demand to adequately serve this load and provide for some uncertainty in assumptions. Several comments received by the company through the IRP Public Process noted that the 15% planning margin PacifiCorp chose to use for capacity planning was based on potential Standard Market Design (SMD) outcomes. Comments suggested that given the importance of the assumption, PacifiCorp should perform a loss of load probability (LOLP) study to determine an optimal planning margin.

In response to public inquiry, PacifiCorp created an Action Item in the IRP to further examine planning margin prior to the next IRP process. The action item calls for PacifiCorp to:

> *"Determine the Planning Margin PacifiCorp will adopt if different from the 15% planning margin adopted in this IRP, following the outcome of the FERC's proposed SMD rule. The analysis for this will include loss of load probability studies."*

The purpose of this study is therefore to determine the planning margin PacifiCorp will adopt in its 2004 IRP by: i) defining planning margin and system reliability, ii) reviewing FERC and other utility and regional committee views on planning strategies, iii) comparing modeled system reliability and incremental cost over a range of planning margin targets.

This study:
- Presents background and explains the importance of the selection of a planning margin
- Discusses the function of planning margin in ensuring generation adequacy
- Evaluates the adequacy of planning margin to ensure generation adequacy
- Evaluates several alternative measures to ensure generation adequacy, including Expected Unserved Energy (EUE) and LOLP
- Recommends an appropriate level of planning margin for PacifiCorp's 2004 IRP to:
  - Procure adequate resources to meet load requirements
  - Avoid physical short exposure to markets
  - Ensure safe, reliable, low cost energy for the consumer

UNDERSTANDING PLANNING MARGIN

It is useful to understand the definition, history and purpose of planning margin before attempting to determine the appropriate level of margin to adopt for the system and recognize the limitations of resource planning based solely on this assumption. The following is a brief description of planning margin, its intended function, and several sample calculations.

Definition and Function of Planning Margin

A load-serving entity (LSE) such as PacifiCorp has an obligation to meet the capacity and energy needs of its customers. Utilities routinely evaluate their expected future resources against their expected future peak demands. Often referred to as a Load and Resource analysis (or "L&R"), this study helps a utility determine its expected annual capacity surplus or deficit. For a number of reasons including the random nature of generator outages, the utility's inability to store significant quantities of power, and uncertainty in future customer demand, a utility is required at all times to possess a greater amount of capability than its expected demands. This extra amount of capability, or reserve, enables the utility to meet these challenges and uncertainties.

Reserves

An electric utility holds various types of reserves. The two most basic reserves are operating reserve and planning reserve.

Operating Reserve is defined as that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages, and local area protection. This reserve can be comprised of generators running below their peak capacity, standby generators, firm purchase agreements, and interruptible load. On a large system such as PacifiCorp's, operating reserve requirements can easily exceed six hundred megawatts at any time, with at least 50% of the requirement held as spinning reserves.

Planning reserve is the difference between a control area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand. It is the long-term planner's tool to identify needs for additional resources so that Operations staff will have sufficient operating reserves in the future. Planning reserve is also commonly referred to as planning margin.

This document will herein use the term planning margin, which is conceptually equivalent to planning reserve or planning reserve margin.

The planning department of a utility is responsible for identifying the need for resources well in advance of expected demand growth. By identifying the need for new generating units or purchase agreements several years from their need, utility planners facilitate the acquisition of the resources necessary for the eventual operation of the system.

Planning margin can be expressed as a quantity of reserve (MW) or as a percentage of reserve above the peak system demand (%):

Planning margin (MW)	=	Expected Annual Peak Capability – Expected Annual Peak Demand
Planning margin (%)	=	(Expected Annual Peak Capability – Expected Annual Peak Demand) / Expected Annual Peak Demand

The Expected Annual Peak Demand is the maximum hourly value of the quantity: Retail Load + Long-Term Firm Wholesale Sales. The Expected Annual Peak Capability is the amount of owned generating capacity plus Long-Term Firm Wholesale Purchases at the hour of peak system demand. It is the sum of thermal, hydro, wind, firm purchases, and other generator's capability at the hour of peak system demand before planned outages, forced outages, or operating reserves. This full-number rating is also referred to as notional-physical capacity.

Table N.1 presents a four-year load and resource balance for a hypothetical electric utility:

Table N.1 – Hypothetical Utility Load & Resource Balance – 15% Planning Margin

	2004	2005	2006	2007	Total Four-Year Resource Additions (MW)
Expected Annual Peak Demand (Load, MW)	10,000	11,200	12,000	13,000	
Expected Annual Peak Capability (Resources, MW)	11,500	11,250	11,000	11,000	
Planning Margin before New Resources	15%	0.5%	(-8.3%)	(-15.4%)	
Total Resources Required to Meet 15% Planning Margin Target (MW)	11,500	12,880	13,800	14,950	
Resource Deficit (MW)	0	1,630	2,800	3,950	
Annual Build (MW)	0	1,630	1,170	1,150	**3,950**

In 2004, this utility forecasts a peak system demand of 10,000 MW. The utility will have 11,500 MW of available resources to meet this load. The utility would calculate its 2004 planning margin as follows:

2004 Planning margin = (Resources – Load)/ Load
= (11,500 – 10,000) /10, 000
= 15%

Assuming the utility targeted to a 15% planning margin, no additional resources would be required for 2004. For the same utility in 2005, however, the planning margin with existing resources is as follows:

2005 Planning margin = (Resources – Load)/ Load
= (11,250 – 11,200) / 11, 200
= 0.5%

Again assuming the utility targets a 15% planning margin; it will need to acquire additional resources to meet the margin. Either building units or purchasing firm power can do this. To determine how much additional capacity the utility needs in 2005, it must first calculate the total of all resources needed in 2005 to meet its 15% planning margin target:

2005 Resources Required to Meet 15% Planning Margin Target = 2005 Expected Annual Peak Demand * (1 + Planning Margin)
= 11,200 * (115%)
= 12,880

Next, the utility compares the calculated resource requirements with its projected existing resources:

2005 Resource Deficit	=	Resources Required to Meet 15% Planning Margin Target – Expected Annual Peak Capability
	=	12,880 – 11,250
	=	1,630

The utility must procure 1,630 MW of additional resources for 2005 in order to satisfy its 15% planning margin requirement. The selection of planning margin directly influences the amount of resources a utility will plan to build or buy.

If this sample utility had a 20% planning margin requirement, they would be deficit by 500 MW in 2004, whereas the utility targeting a 15% planning margin had no deficit in 2004. An upward change in planning margin target has the largest impact in the earliest year. The difference in incremental additions needed to maintain differing planning margins is substantially less significant than the first year of reaching the new target margin.

Measures of Reliability

Resource adequacy reduces the probability of load loss, mitigates market power transactions, and reduces wholesale price volatility. Planning margin is one of several techniques to balance the tradeoff between adequacy and cost constraints. Other planning techniques include combinations of reserve requirements, generation outage rates, and single largest contingency. The ideal planning margin will provide adequate resources when needed in future years with enough cushion to ensure that the reliability requirements of the system are met.

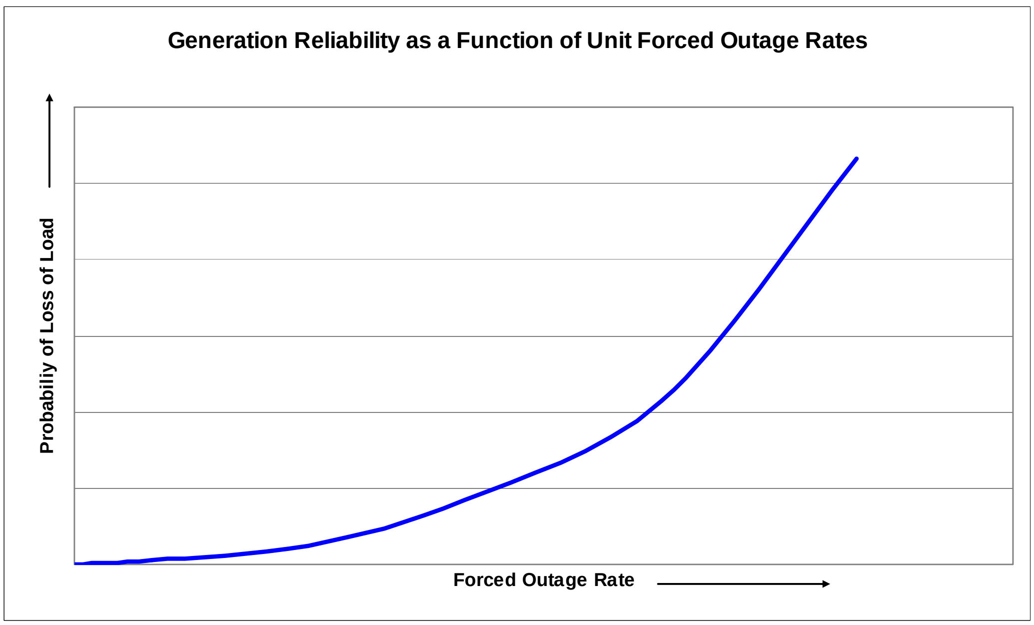
Reliability is the degree of performance of the system that results in electricity being delivered to customers within accepted standards and in the amount desired. The frequency, duration, and magnitude of adverse effects on the electric supply serve as measures of system reliability. LOLP can be measured in various ways but is most commonly the sum of each day’s probability of a loss of load instance occurring at the daily peak hour over one year. For example, the probability that available resources cannot meet the peak daily load in that day is calculated for each day of the year and summed. As will be described later, LOLP studies are now performed by calculating the probability of not meeting load for every hour when key system variables are stressed stochastically over multiple iterations. Many utilities and pools in the United States and other countries established a criterion of load exceeding the available capacity no more than one day in ten years although the methodology for its calculation is not standard.

LOLP addresses the frequency of reliability disturbances occurring but does not address the magnitude of the unserved load, which will impact resource type and sizing decisions of long term planning. Energy not served or ENS is the amount of obligation not covered by available generation over a time period. EUE is the average of the ENS over several iterations of potential outcomes when system variables are stressed with stochastic parameters. EUE is the best measure of curtailment magnitude but makes system-to-system comparisons difficult for the same reason. As a result, a large system with large incremental resources will see higher levels of EUE but may have the same LOLP as a smaller system. EUE results can be normalized for multiple systems by looking at the percent of EUE over the system load.

One Planning Margin, Many Reliabilities

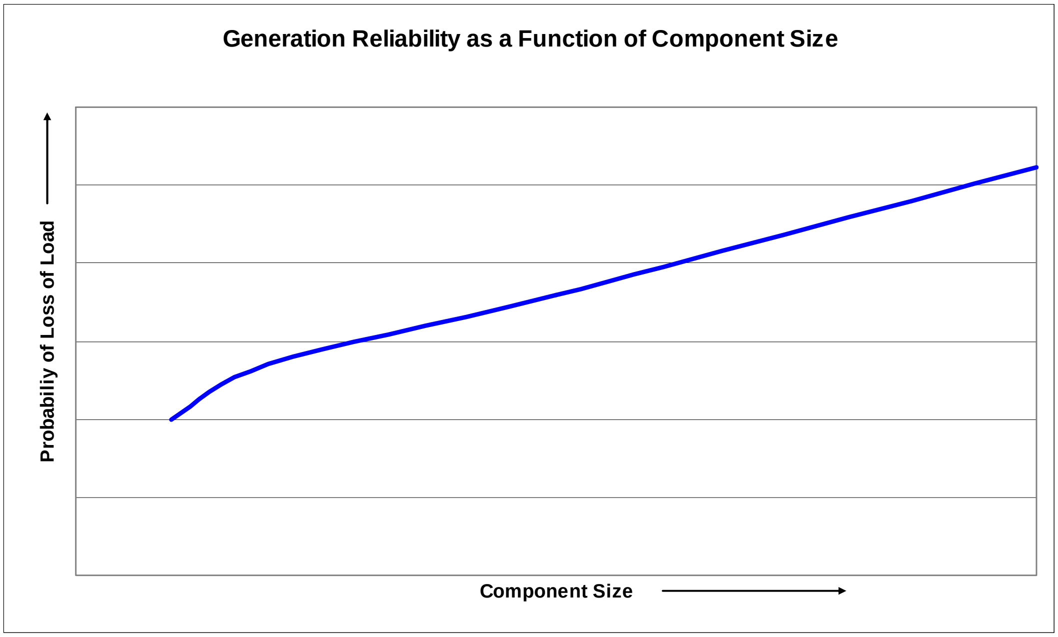
Although planning margin may create a straightforward calculation for the amount of capacity additions needed, planning margin alone will not ensure system reliability. LOLP and EUE should be maintained or improved through the planning process. Planning margin does not account for differences in forced outage rates, composition of resource additions and existing generation, load size of a system, or the system's load volatility. Each of these system variables can impact reliability when a constant planning margin is maintained as shown in the general trends in Figures N.1 through N.4.

Figure N.1 – Reliability vs. Forced Outage Rate



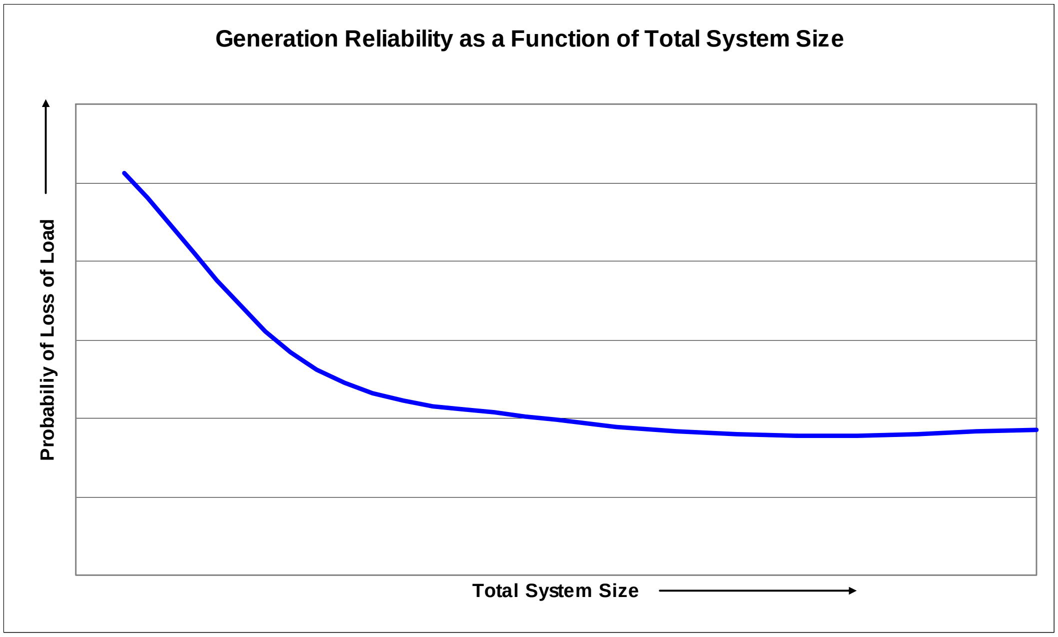
Holding system size, component size, and load uncertainties constant, system reliability decreases as forced outage rates (FOR) increase. Systems with less reliable units (i.e., higher FORs) will perform worse than systems with more reliable units (i.e., lower FORs).

Figure N.2 – Reliability vs. Component Size



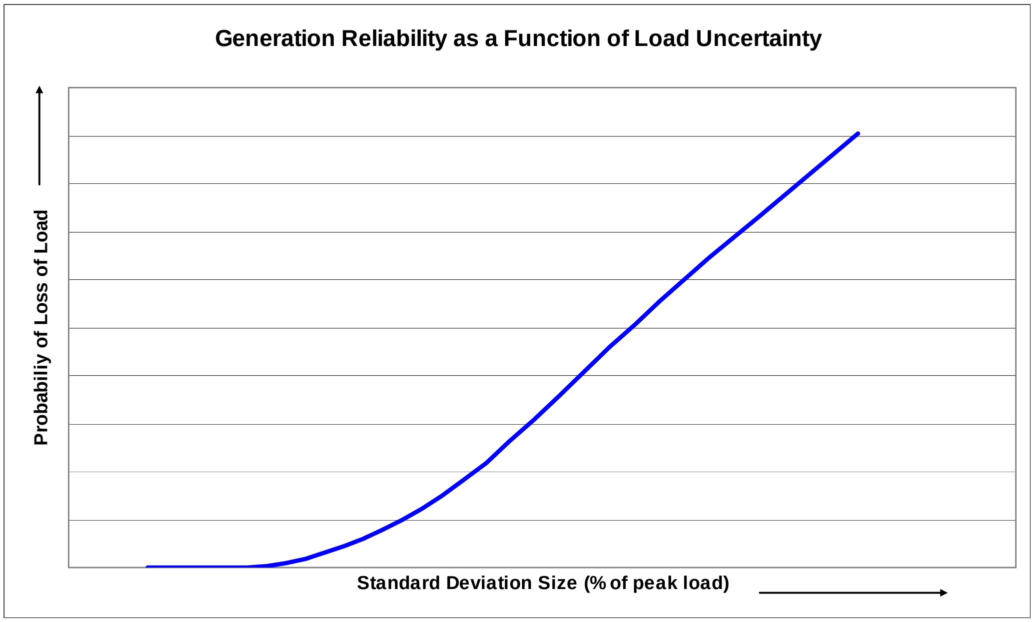
In general, as more, smaller generators are used (holding system size, FORs, and load uncertainty constant), the system is more reliable. Systems of the same size but with more, smaller resources are less likely than a few, larger resource to have a critical number of units offline at the same time.

Figure N.3 – Reliability vs. System Size



In general, as overall system size increases (additional resources added with the same composition and FORs and load uncertainty is held constant), the reliability of the system increases. Smaller systems depend on a few resources to operate. As the system load size and number of generating units increase, the probability that a critical number of resources will be unavailable decreases.

Figure N.4 – Reliability vs. Load Uncertainty



As load uncertainty increases, the probability that load will be greater than available capacity increases.

The benefit to using a planning margin for capacity planning is that it can be calculated quickly and is easy to communicate whereas the reliability measures such as LOLP and EUE require the use of more sophisticated modeling techniques and resources to produce. Planning to meet first a planning margin and then adjusting the size or type of some portfolio resources if necessary to meet reliability standards is a valid approach to reliable and adequate planning. PacifiCorp may choose to incorporate this additional level of resource screening analysis in its portfolio development for the 2006 IRP.

DETERMINATION OF OPTIMAL PLANNING MARGIN

What is the optimal planning margin which will provide adequate system reliability at a reasonable cost? The answer to this question is really system specific. As was just illustrated, one planning margin can result is a range of reliabilities depending on the system load variability and size as well as resource size and outage rates.

Regional Adequacy Planning

Organizations and committees across the country are addressing resource adequacy standards for utility planning. Table N.2 is a summary of planning margin and reliability targets set by regional organizations as of April 2004. WECC and SERC are the only Councils without either a specified resource adequacy criteria or planning reserve margin. The most common resource adequacy criteria are the 1-in-10 yr LOLP or 1 in 10 LOLE, which as described previously, are seen as industry standard reliability thresholds.

Table N.2 – National Planning Margins and Adequacy Criteria

(See note below)	WECC	MAPP	SPP	ERCOT	MAIN	ECAR	FRCC	NPCC	SERC	MAAC
Planning Margin	Not specified	15%, 10% if hydro system Planning Margin	12%, 9% if 75% hydro Planning Margin	12.5% Planning Margin	15-20% Planning Margin	0.1 day/yr LOLE	15% Planning Margin	Not specified	Varies by member system	Based on LOLE criterion
Regional resource Adequacy Criteria	Not specified	1-in -10 yr LOLE	1-in -10 yr LOLP	Not specified	1-in -10 yr LOLP	Use of supple-mental capacity for 1-10 d/yr (DSCR)	1-in -10 yr LOLP	LOLE by discon-necting firm load due to resource deficien-cy no more than 0.1 d/yr	No uniform criterion for entire region	LOLE of 1 day/10 years or 0.1 day/yr
Methodo-logy	Not specified	Margin derived using LOLE 1-in-10	LOLE analysis	Reserve Margin based on LOLE studies	Based on LOLP and LOLE studies	1 to 10 days DSCR consis-tent with LOLE 1 in 10 yr	Periodic analysis of LOLP for reserve margin	Based on LOLP and LOLE studies	Not specified	PJM approval of the required margin

Note: Source for table Westwide Resource Assessment Team (WRAT) Resource Adequacy Briefing Paper, March 23, 2004.

Western regional energy policy committees are devoting increasing amounts of time and resources to the discussion of regional resource adequacy in the wake of the 2001 energy crisis and recent reliability issues experienced in the Midwest and on the East Coast. These committees have potential to influence state and federal legislation based on the outcomes of their investigations and therefore influence the planning strategies of all western utilities.

The findings of these committees seem to name the common problem areas for regional planning as the lack of information sharing and common understanding of definitions, and the existence of multiple and differing planning methods of area utilities. The ideal regional situation for long-term resource planning WECC-wide would be to have perfect information sharing between utilities and government agencies for load forecasts and bulk-power system status estimates for generation and transmission. Without this collective information, utilities have no choice but to plan to build to meet all expected loads and not rely on market generation. This strategy could result in a system that may be reliable but not an efficient use of the regional electric system. A valid, regional load and resource database could make it possible for utilities to better model interconnected market depth and liquidity.

<u>Efforts to Achieve the Ideal</u>

There have been several recent joint-agency/utility attempts to improve regional demand and supply information sharing. One of these many efforts was the formation of the Power Supply Adequacy Forum with initial meetings in early 2003. These meetings included PacifiCorp, Bonneville Power Administration (BPA), Portland General Electric (PGE), Idaho Power, Northwest Power Pool (NWPP), Northwest Power and Conservation Council (NWPCC), and other Northwest utilities. These discussions identified that among other things, problems and inconsistencies with the ways resource adequacy is assessed argued for a regional process.

Another Westwide effort is directed by CREPC, The Committee on Regional Electric Power Cooperation, which is composed of state regulatory Commission representatives from all Western states. CREPC established a committee for the purpose of addressing western adequacy planning issues. They've benchmarked the various strategies of regional utilities as described in their IRPs and have started an in depth technical review in conjunction with Lawrence Berkeley Labs of the historical and alternative methods to measure adequacy. WRAT, the Westwide Resource Assessment Team created by CREPC and made up of 17 technical staff representing nine western states, the Northwest Power and Conservation Council and British Columbia, has made recommendations to CREPC on the challenges facing resource adequacy issues and potential approaches to handling them. These challenges include a lack of common understanding and definitions, the variety of strategies and use of differing terms to define these strategies, uncertainty of regulatory recovery, responsibility, incentives, and the challenge of waiving environmental protections for the sake of resource adequacy. Possible approaches to addressing these challenges include: development of transparency of load and resource information, and the definition of adequacy metrics at regional and sub-regional levels with voluntary targets and/or enforceable standards.

WECC created a Resource Adequacy Workgroup to establish the tools, methodology, and data requirements for conducting power supply assessments for the region through a three-phase work plan. The results of their power supply assessments will guide their recommendations to the WECC Planning Coordination Committee for potential Resource Adequacy Criteria. This December, the Resource Adequacy Workgroup will submit a report of their Phase I findings to the WECC Reliability Subcommittee.

At the state level, the California Public Utilities Commission has recently defined a reserves and resource adequacy threshold of 15-17% planning margin. All Load Serving Entities in California are required acquire sufficient reserves to meet its customers' load and to maintain a planning reserve margin of 15-17% for all months of the year by June 1, 2006. 90% of peak load plus reserves must be made with commitments made at least one year in advance. Resource adequacy workshops are ongoing to provide a discussion forum for utilities and create common definitions among groups.

Finally, on the transmission side of planning issues, the Seams Steering Group Western Interconnect, SSG-WI, the collaboration of CA ISO, Grid West and RTO West Connect, has worked with PacifiCorp to develop a public database which the three RTOs have committed to maintain for three years.

EVOLUTION OF PACIFICORP'S PLANNING MARGIN CRITERIA

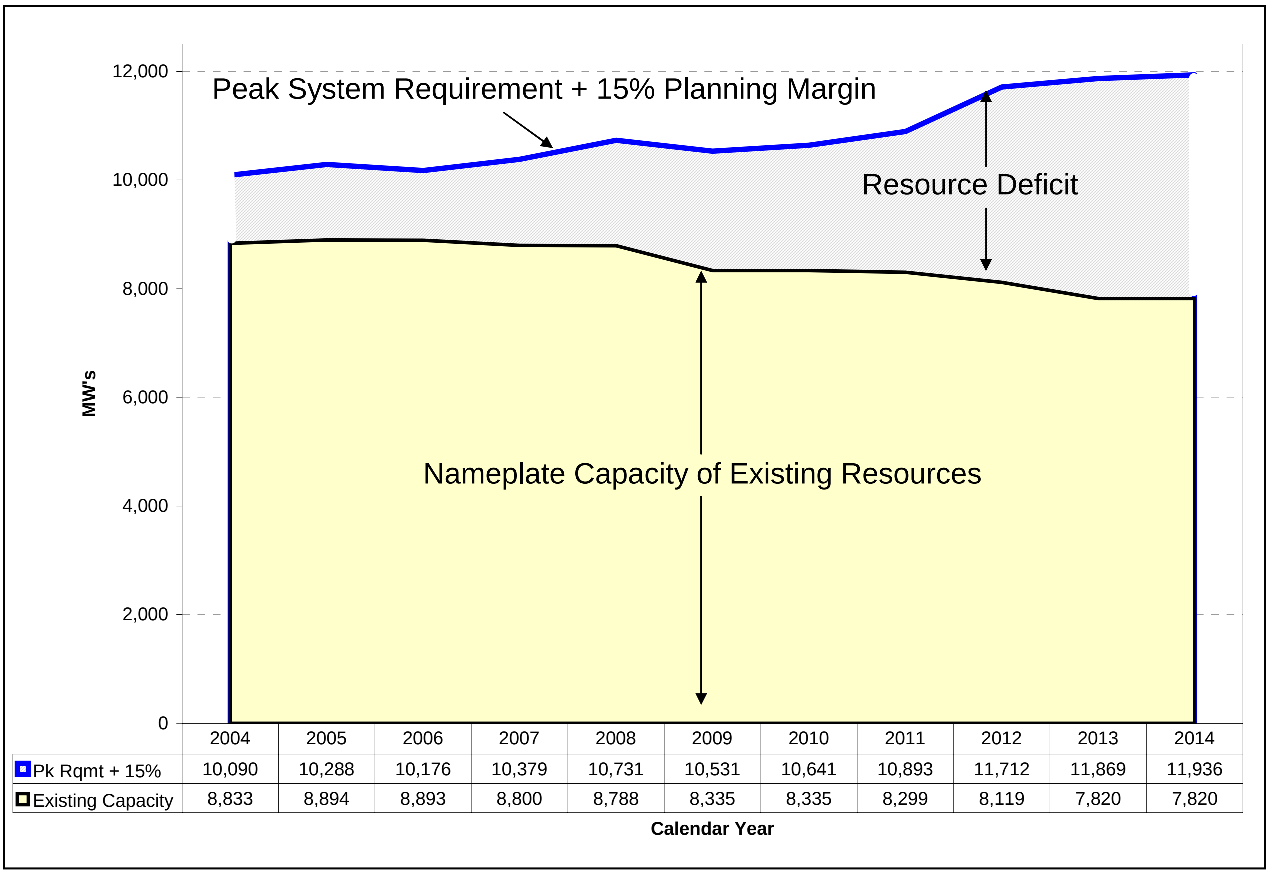
PacifiCorp has been working on determining the optimal planning margin for its system since the 2003 Integrated Resource Plan. This section will track PacifiCorp's evolution through this process by reviewing the events dealing with planning margin for the following plans;

- The January 2003 IRP
- The October 2003 Update
- The 2004 IRP

<u>PacifiCorp's 2003 Integrated Resource Plan</u>

In the 2003 Integrated Resource Plan, PacifiCorp listed its forecast peak requirement plus 15% planning margin versus its projected existing capacity. This chart is reproduced below as Figure N.5.

Figure N.5 – PacifiCorp Load & Resource Balance (January 2003)



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

The chart shows a declining base of existing resources, an increasing peak system requirement plus 15% planning margin, and the corresponding resource deficit. The remainder of the IRP focuses on "filling the gap," or securing resources to meet the peak system requirement plus a 15% planning margin.

PacifiCorp used a 15% level of planning margin in the 2003 IRP. The selection of 15% was based upon the middle value of the 12% to 18% range suggested in the Federal Energy Regulatory Commission's proposed Standard Market Design Notice of Proposed Rulemaking (FERC SMD-NOPR), issued July 31, 2002. Below is a summary of the resource adequacy provisions in the SMD-NOPR, followed by a benchmark of planning strategies of other western utilities.

Summary of Resource Adequacy Provisions in SMD-NOPR

FERC identified several reasons to include a resource adequacy requirement in their Standard Market Design proposal. First, FERC highlighted their belief that spot market prices alone will not signal the need to begin development of new resources in time to avert a shortage (particularly important given the lead-time for construction of new generation or transmission). Furthermore, by rushing to install capacity, a utility may be biased toward quick construction versus long-term cost minimization, environmental goals, or fuel diversity.

FERC cited the lack of visible price signals and price-responsive demand as two current market shortcomings. Customers (even those in retail competition) are often unaware of the true hourly cost of producing energy. Regardless, most would not be able to respond to real-time prices because of current rate design or metering limitations.

Secondly, FERC recognized that spot market prices subject to mitigation measures might not produce an adequate level of investment when a shortage occurs. Without periods of higher-than-normal market prices, investors may conclude prices will be insufficient to cover their costs of new generation. Price caps limit the prices generators may charge for power when resources are tight, but the lack of high prices (and therefore scarcity premiums) may prevent construction of peaking resources that rely on infrequent, yet very high prices to justify investment.

Finally, FERC addressed an economic "free-rider" problem of load-serving entities under-investing in resources needed for reliability when they can depend on the resource development of others. Without a universal rule requiring utilities to procure adequate resources, a load-serving entity has a strong incentive to minimize its net power costs by holding minimal planning reserves, relying on other utilities in a crisis. As LSEs adopt this strategy, it would lead to systematic underinvestment. Furthermore, in an interconnected system, failure of one utility to procure adequate resources can contribute to a shortage affecting reliability and spot prices for all market participants.

Components and Enforcement

The NOPR proposed to require an Independent Transmission Provider (ITP) to forecast regional demand and facilitate determination of future resource requirements to ensure adequate supplies, and assign each load-serving entity in the region a share of the capacity based on the ratio of its load relative to the region.

A Regional State Advisory Committee (RSAC) would be responsible for determining the appropriate level of future resources. FERC recommended reserve margins should be no lower than 12%, two-thirds of the typical historical reserve margin target of 18% for large utilities. They noted that systems with an 18% planning margin corresponded to a "one day in ten years loss of load probability." They proposed the 12% minimum as a 'safety-net' to prevent market illiquidity, high-sustained prices, and shortages. FERC encouraged regional discussion of appropriate planning targets in energy-limited areas, specifically on how to incorporate volatility of annual hydropower supply.

In theory, regional forecasting and planning would enable better forecasts by replacing single-utility forecasting with regional forecasting. Once the RSAC determined the appropriate level, the ITP would analyze the regional load and resource forecast, determine the amount of additional resources to meet the adequacy level, and calculate each utility's share of the additional resources.

FERC proposed two methods to allocate resource responsibility among LSEs.

1. Base allocation on ratio of current-year load to total load of region (FERC noted that this method was less subject to manipulation, but that areas with lower (or negative) load growth would subsidize utilities with higher load growth).
2. Base allocation on ratio of future-year (e.g., three years out) load to total load of region. (This approach may deal fairly with different growth patters within a region).

Each utility would be responsible for procuring resources to meet its share of future needs. This could be done by either increases in supply or decreases in demand. Resource additions could be self-owned generation, local distributed generation, or firm bilateral contracts backed by specific units (which could not be counted towards another utility's resource adequacy requirement). Reductions in demand could be biddable and interruptible load.

An LSE could choose a higher level of reliability by procuring supply and/or demand response resources beyond the ITP requirement.

Benchmark of Western Utilities Planning Strategies

Absent regulatory guidance about the appropriate level of planning margin, PacifiCorp reviewed planning margin assumptions of other Western electric utilities. The findings suggested that a 15% planning margin level was consistent within the range of equivalent planning margins of other Western utilities (see Table N.3). Each utility listed has formulated their own approach to calculating the optimum level of resources for their system. PacifiCorp plans to cover the peak system obligation while some other utilities use their peak load hour for resource planning. Additional planning to meet energy constraints is also considered in various ways at these utilities depending on resource characteristics of each system.

Table N.3 – PacifiCorp's Planning Margin Relative to Other Western Utilities

Utility	Equivalent Planning Margin Assumption	IRP/ Least Cost Plan
Nevada	12% reserve above peak load	2003
Avista	≈ 12% through 2009[1]	2003
Idaho Power	≈ 12% [2]	2004
PacifiCorp	15%	2003
Portland General Electric	12% [3]	February 2003 Supplement to 2002 IRP
Public Service of Colorado	17% reserve above peak load	2004
Puget Sound Electric	≈ 14.5-15% [4]	2003

Notes:

[1] Build to 80% confidence level
[2] Covers peak at 70% water and load conditions
[3] 6% operating reserves with 6% additional planning reserve
[4] Based on peak load with average water conditions at 16 degree F

Table N.4 – PacifiCorp's Energy Planning Strategy Relative to Other Western Utilities

Utility	Energy Planning [1] Assumption	IRP/ Least Cost Plan
Nevada	None specified	2003
Avista	1-in-10 year LOLP	2003
Idaho Power	70 percent load and water conditions	2004
PacifiCorp	Net short position limited to less than 5% of hours per year, average water conditions	2003
Portland General Electric	Critical water conditions	2002
Public Service of Colorado	None specified	2004
Puget Sound Electric	Average water conditions	2003

Notes:
[1] Source: WRAT 3/25/04 presentation on Western Resource Adequacy

Within this review of seven Western utilities, there are seven different planning methods but all plan for the equivalent of between a 12% and 17% reserve margin. PacifiCorp therefore concluded a planning margin of 15% in its 2003 IRP was appropriate, recognizing that more or less planning margin could be warranted. The selection of 15% was made based on the best information available at the time.

PacifiCorp's October 2003 Update

The 2003 IRP noted some of the unique concerns of the two control areas where PacifiCorp operates- West and East. The gap in PacifiCorp West is a result of a financial and energy problem, whereas the gap in PacifiCorp East is a transmission and capacity problem.

In October 2003, PacifiCorp filed an update further detailing the unique challenges of each control area. This update segmented the position by location as described in Table N.5.

Table N.5 – PacifiCorp Tier 1 & 2 Segments

Segment	Region	Description
Tier 1	Utah "Bubble" The loads, resources, and contracts in Southeast Idaho, Utah, and Southwest Wyoming [west of Naughton].	Risk of insufficient resource capacity within a transmission-constrained area to meet the maximum firm capacity obligation
Tier 2	Remaining short position Remaining PacifiCorp system less the Utah "Bubble"	Risk of insufficient energy resources in an unconstrained area

While this segmentation divided the system into two planning concerns, it did not negate the need for planning margin. In Tier 1, the capacity- and transmission-constrained area of the PacifiCorp system, a planning margin was used to ensure adequate resources to meet peak system demand. This planning method is more in line with the way the short-term operations planning staff balances the forward position.

In an attempt to further bridge the gap between short and long term planning methods, a review of the current short and near term planning methods to balance the forward position and the equivalent planning margin for the system achieved through this method was completed.

This prescriptive look is an investigation into the planning margin level resulting from a resource build plan that follows the current company methods of determining and balancing the short to near term system position.

Current Short Term Planning Methods

The Commercial and Trading group's (C&T) operations planning area works to cover the short to near term energy and capacity position for the system on a continuous basis with the goal of ensuring that adequate resources will be available to meet projected demands throughout the system. The measure of adequacy of resources to meet load varies by location in the system. As introduced in the PacifiCorp 2003 IRP update, C&T plans to meet system needs by considering two Tiers of regions within the system.

- Tier 1 (Delivery Risks) – Tier 1 represents the risk of insufficient resource capacity to meet PacifiCorp's maximum firm capacity obligation. PacifiCorp's planning criteria for Tier 1 is to cover the peak hour notional physical position for the transmission-constrained Utah and Goshen regions.
- Tier 2 (Financial Risks) –Tier 2 represents the financial risk associated with meeting PacifiCorp's overall energy obligation. The planning criteria for Tier 2 is to cover average monthly notional physical energy fixed-price energy HLH, LLH, and flat positions in the east and west areas. With the additions of resources to meet the peak conditions of Tier 1 in the East, the Tier 2 East resource needs are covered as well since fully loading the imports to the Utah "Bubble" require the entire East control area to be balanced.

Load and Resource balances are used to calculate these system needs using expected load forecasts and existing resources.

Short Term vs. Long Term Planning

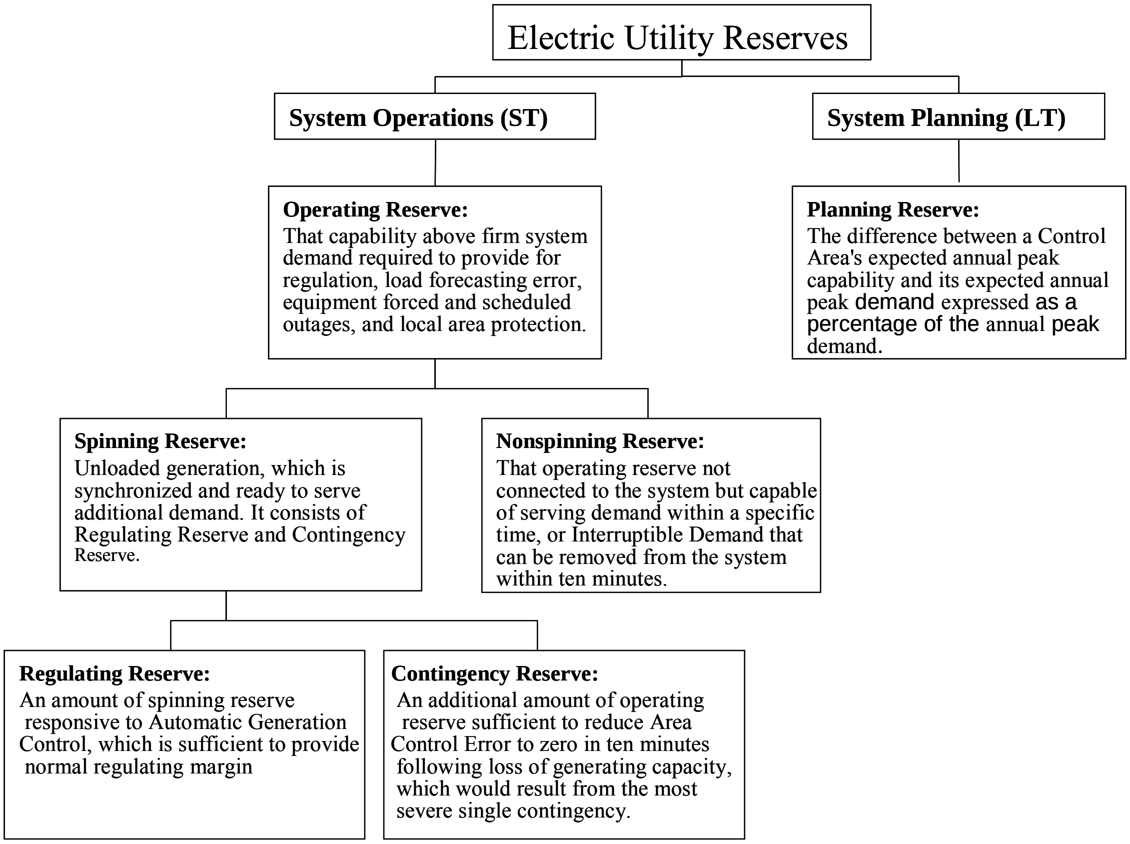
The differences between planning techniques for short and long-term system resource needs are driven by the impacts of differing time horizons on the variables that affect the system position. For example, load forecasts are much more certain over the short term than they can possibly be looking 20 years out. Since resource procurement decisions must be made well in advance of the time they are operational, long term planning must meet known requirements for reserves with an additional understanding of load volatility. Table N.6 lists the differences between short and long term planning by looking at how loads and resources can be impacted by differing time horizons.

Table N.6 – Differences between Short-Term and Long-Term Planning

Load Forecast	Short-term Operations	Long-term Planning
Weather Trends	• Awareness of adverse weather conditions can necessitate arranging for extra resources to cover any surge in demand	• Historical average, minimum, and maximum temperatures are used to develop the long-range demand forecast
Economic Trends	• Includes up to 24 month forecast of economic trends	• 20 years projections of growth or recession impact long range demand
New Usage Trends	• Limited changes to customer usage behavior in the short term	• Forecasts predicting increased use of air conditioning greatly impact shape and magnitude of load forecast
Efficiency Trends	• Limited efficiency changes reflected as known over the short term	• Adoption of energy-efficient appliances and/or demand-reduction programs is uncertain, leaving shape and magnitude of load forecast in doubt
Available Generation	**Short-term Operations**	**Long-term Planning**
Unplanned Outages & Maintenance Outages	• Reasonable estimates for emergency power purchased from neighboring utilities and the existing ability to import the power to cover outages	• Difficult to estimate how much generation (and transmission rights) will be available to rely upon in a system emergency
New Power Plants & Early Retirements	• Location, size and average outage rate of existing resources is known	• Difficult to estimate size, timing, location, etc of new power plants (other utilities, IPPs) when others will retire resources
Hydroelectric Generation	• Although even the short-term water supply may be unknown, operational constraints for hydro resources are known.	• Use historical distribution of water years for generation estimate. Hydro's existing ramp-rate may not be available in the future due to new operational restrictions
General operational restrictions	• Assume no changes to existing operating restrictions	• Potential changes to environmental / air quality restrictions and individual plant capabilities which may reduce generation are included in long-term resource assumptions.

Figure N.6 illustrates the difference between the two load and resource outlooks from a reserves standpoint. In the short term, the required operating reserves must be met each hour and in the long term, the same requirement will hold but there's an additional element of variability in forecasting demand levels into the future.

Figure N.6 – Electric Utility Reserves



Note: All definitions from North American Electric Reliability Council's (NERC) Glossary of Terms [39]

Equivalent Planning Margins from L&R Balance

Following these methodologies for sample fiscal year 2009, Table N.7 displays the East equivalent planning margin as 15% and the West planning margin as 24% calculated on the peak system load hour.

Table N.7 – Equivalent Planning Margin Calculation by Obligation – Balanced Positions

Area	**Obligation** (Load + Sales) (MWs)	**Resources + Purchases** (MWs)	**Existing Planning Margin**	**Resource Additions needed to balance Tier 1 position** (MWs)	**Planning Margin** (MWs)
West	3,409	3,829	12.3%	385	23.6%
East	7,102	6,693	-6%	1,479	15.1%
System	10,511	10,522	0%	1,864	17.8%

[39] NERC Glossary of Terms: http://www.nerc.com/glossary/glossary-body.html

It is apparent that the West planning margin seems high. This can be explained by several characteristics of that system and the load and resource balance which are controlling the relative size of the planning margin.

The shortest West position is the flat, August position. Although the average load is low (2,431 MW Flat vs. 2,707 MW HLH and 3,501 MW peak) contracts net to 200 MW for the flat position, the BPA peaking contract nets out to 0 MW contribution and system hydro is only 285 MW. Compared to the August system peak hour position where the BPA contract adds 575 MW capacity, hydro resources provide 631 MW, and contracts net to almost 400 MW it's apparent that planning for the flat position is important. Planning margin, however, is calculated for system peak hour when resources and contracts are at their highest level of contribution.

Another reason for the West appearing to need a large resource margin was due to the assumption that the West is providing 100 MW of East reserves all hours. These additional 100 MW are built into the planning assumption for the West and represent 3% of the planning margin.

Pros and Cons of L&R Approach

There are benefits and drawbacks associated with using short term planning techniques for long-term resource planning application. On the positive side, this methodology is more closely aligned to the current operational approach and is system specific by considering forced outage rates, reserve requirements and transmission constraints.

Although this approach is more robust than the previously used planning margin constraint of 15%, it also has its drawbacks. Short-term planning methods assume expected demand and average hydro conditions will persist every year, allow no variation in demand forecast and assume no market access for emergency purchases which can result in an "island effect". PacifiCorp's proposed approach to finding the optimum planning margin builds on the "Pros" of this approach and addresses the "Cons" for a better systematic approach to the resource adequacy issue.

2004 IRP Approach

PacifiCorp asked Henwood Energy Services to examine the effects of varying levels of planning margin on system reliability with a loss of load study. The loads and resources for FY2009 (April 1, 2008 – March 31, 2009) were built to several levels of planning margin. A stochastic simulation of each portfolio returned useful information about the impact of various planning margins on system reliability and the costs associated with incrementally reducing unserved energy. Stochastic simulation in MARKETSYM ensures multiple iterations of hourly loads and available resources.

The following outputs are produced and tracked in this study:

- LOLP as a function of planning margin – LOLP is tracked and reported by MARKETSYM. A Loss-of-Load hour is an hour where demand exceeds supply. Loss-of-Load hours do not indicate magnitude or duration of the loss-of-load. Results are given as number of days with loss-of-load (24hrs) in ten years.
- EUE as a function of planning margin – EUE is the average amount of ENS, measured in MWh, across all iterations of the stochastic simulation.

- Cost of EUE Reductions as a function of planning margin – Cost of EUE reductions is the incremental capital cost of new resources added for each planning margin level compared to the lower levels of EUE achieved by building to lower planning margins. This comparison will show the increasing cost to achieve higher levels of reliability. The new resource costs include a fixed charge rate of 15% to take into account capital costs, depreciation, income taxes, property taxes, insurance and fixed O&M. When distributed over the life of the plan, an annual rate of $72/kw/yr results. No variable costs associated with system operations are included in this measure.

Overview of Recently Accepted Approach

Henwood's approach in this study is similar to that which it took while assisting four different investor-owned utilities (PG&E, SCE, PSCO and SDG&E). The methodology employed involves performing hourly economic dispatch of resources against loads for each hour of one year. Henwood's MARKETSYM simulation product was utilized. The model allows the user to generate multiple stochastic outcomes (driven by probability theory) of the simulation in order to include uncertainties in operation of the electric system, including unit forced outage, hydro availability, and load level variations caused by weather.

What does "stochastic" mean? Generally, the word stochastic is used to indicate that a particular input parameter has an element of randomness to it, and its value at a given time can be predicted by probability theory (i.e., how likely a particular outcome is). Stochastic is often used as the counterpart of the word "deterministic," which means that random phenomenon are not involved. A Base Case or single-point forecast of monthly natural gas prices, for example, is deterministic—an expected outcome. However, we know with near certainty that the expected forecast will not actually be what occurs in the future—due to any number of factors. So, it is important in any forecasting to simulate a large number of potential outcomes and understand their range and frequency, and in this case more specifically, how a particular portfolio or system will perform under uncertainty.

Under each full-year simulation (iteration) of the study, Monte-Carlo draws were made daily that adjusted load levels either upward or downward. Further, weekly Monte-Carlo draws were made to reflect occurrence of unit forced outage and to separately determine hydro availability for the given period. The analysis also included assumptions about the ability to call upon emergency supply from other supplies in the Western Electricity Coordinating Council (WECC). Henwood performed 100 iterations of the simulation of the PacifiCorp system.

This stochastic analysis was performed for PacifiCorp's system for a range of planning margin levels. Adding generic Simple-Cycle Combustion Turbines (SCCTs) to each side to build up the resource levels relative to obligation created each planning level.

The major outputs from the simulations are the expected frequency of unserved energy occurrences (LOLP) and magnitude of such events (EUE). For example, in a single iteration for FY 2009 there 8,760 hours where generation is being used to meet load. Load in each hour is a function of both the expected, or base case, hourly load forecast base and the Monte Carlo draw that adjusts the load up or down to reflect weather volatility. Generation outages are also determined by Monte Carlo draws. In some hours there may not be sufficient supply to meet load. The analysis keeps track of the number of MW of load not met in each hour of the iteration. The total unserved energy for that iteration is the summation of the hourly energy not served in that iteration. Given different Monte Carlo draws in the different yearly iterations, each yearly iteration will have a different quantity of unserved energy. In many iterations of a year, there will be no unserved energy. Averaging the quantity of annual unnerved energy in each of the 100 simulations of the year gives the EUE for FY 2009.

In addition to EUE, other simulation outcomes are the LOLP in hours or days in ten years, and EUE as a percent of load across a range of planning reserve targets. From these outputs, Henwood is also able to show the cost of moving from one level of target planning reserve to the next and the corresponding reduction of expected unserved energy resulting from the increased planning reserve level.

Model Assumptions

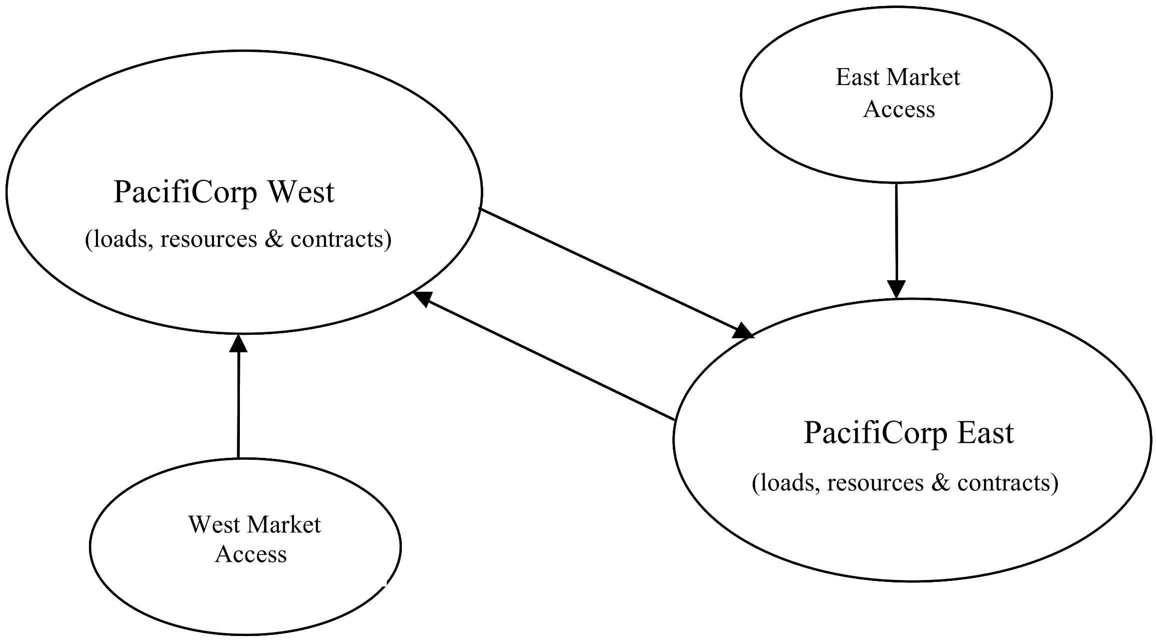
FY 2009 was chosen as the test year for performing this LOLP study. PacifiCorp supplies in FY 2009 are reflected in the analysis including the owned or contracted thermal and hydro units. In addition, PacifiCorp has over 40 contracts that are also depicted as resources (or exchanges or sales). (See Appendix C for a complete list of resources and contracts).

<u>Topology– Western and Eastern Zones</u>

For the 2004 IRP, PacifiCorp locates the loads and resources for its interconnected system in 18 distinct transmission areas (geographic or electrically separated areas) within MARKETSYM. The system also has two control areas—PacifiCorp East and PacifiCorp West. PacifiCorp's East system is thermal based and peaks in the summer. The West system meets approximately 20 percent of its retail load through hydroelectric generation and its load peaks in the winter. This may change in the future, making the West also summer peaking as summer air conditioning usage climbs. The East system is generally considered capacity and transmission constrained, with primary market access at Four Corners. The West control area on the other hand can be energy constrained in years of low hydro runoff, and has access to markets at Mid C and COB.

This planning margin analysis aggregated the IRP topology as shown in Figure N.7 by grouping all loads and resources into East and West control areas. Aggregation of transmission areas decreases processing time without significantly degrading the usefulness of this study's results. The East and West control systems are interconnected in the model with limited transmission capability in each direction. Each of the East and West systems are assumed to be able to access market power up to firm transmission right capabilities.

Figure N.7 – PacifiCorp Planning Margin Study Topology



Loads in the Base Year

Because the analysis will perform Monte Carlo draws to reflect higher or lower than normal loads, it is necessary to begin with an expected hourly profile of PacifiCorp West and East loads in FY 2009 under normal conditions. PacifiCorp provided its expected load forecast for this 8,760-hour period. The annual energy load for PacifiCorp West and East areas in FY 2009 were 21,362 and 39,790 GWh, respectively. The East's load in its peak hour occurred in the summer and was 6,654 MW. The West's expected peak hour occurs in the winter and is forecasted to be 3,501 MW. The system peak occurs in the summer and is expected to be 9,712 MW. The system peak and East peak are not on the same hour. The peak numbers quoted here are 50/50 peak loads, meaning that weather events would be expected to increase the peak load above this level 50% of the time and would be expected to decrease the peak load below this level 50% of the time.

Weather Induced Load Volatility

The largest uncertainty in load in any hour of FY 2009 is caused by temperature variations from normal. The stochastic model Henwood used in this analysis is a "normal mean-reversion" model. By the term "normal" we simply mean that there is expected to be a normal (bell shaped) distribution of loads around the central tendency daily load value caused by daily temperature variations. By the term "mean reversion" we simply mean that if loads in one day are impacted by abnormal weather events, we can determine an average number of days during which these abnormal daily loads will revert back toward the central tendency (normal weather) level.

In order to model future load volatility, estimates of short-term volatility (assumed normal distribution) and mean-reversion parameters statistically developed using ordinary least squares (OLS) regression on historical data. PacifiCorp indicated that the years 1995-2003 were the most representative historical years for purposes of forecasting future weather related demand volatility. The statistical tool estimated the short-term volatility and mean-reversion parameters as follows. Note, daily load in the equations below is measured in GWh per day of daily energy load.

Daily Load (time t) = A + B*[Daily Load (time t-1)] + Error (time t)

Actual daily energy load in MWh for a historical time period are regressed using the above equation and the constants A and B are found that give the best fit for the regression equation. There is an error term for every day ("Error" in the above equation) resulting in a series of error values with a distribution around a mean of zero. Each day's error term is calculated by estimated daily load minus actual daily load. Sigma (short-term volatility) is the standard deviation of this distribution of errors.

During execution, Monte Carlo simulation is performed with daily random draws for average daily values for loads. As discussed above, the assumption is that the distribution of error values is a normal (bell shaped) distribution around the estimated value. The standard deviation of this distribution is derived from the historical daily error values. The Monte Carlo random draw is designed to have this same distribution so that over a large number of Monte Carlo draws a distribution of loads will be developed that reflects the historical distribution.

The MWh energy load draw for a day determines how much, above or below normal, the loads are for the day based on the Sigma parameter. If a day will have 5% more energy load based on the Monte Carlo draw, then the load in each hour must be adjusted so that the energy load for the day is increased by 5%. In the model, each hourly load for the day is adjusted up or down by this 5% factor. Therefore the peak load hours are adjusted more, in MW terms, than light load hours.

Alpha (or mean reversion) = (1-B)

The coefficient "B" found in the regression equation above is used to determine how fast a daily load, once moved away from normal via an abnormal weather event, will revert back toward normal. If "B" is equal to one, then alpha equals zero and there would be no forced movement back toward the central tendency level. This is sometimes called a "random walk." In such a case, a load is only moved by future random draws and moves from the last day's load level. However, in most historical data on daily energy loads it is clear that once a weather event has caused load to vary from normal, then load (and weather) will generally revert back toward a more normal level (i.e., in most regressions on daily load, B is not equal to one). If B equals zero in the above equation, then the next day's load is not related to yesterday's load and load is simply a random event occurring around A. In such a case, a Monte Carlo draw result in day 1 has no effect on the load in day 2. B is generally found to be somewhere between zero and one. As such, load in a following day has some relationship to load in the prior day, but is not tied 100% to the randomly drawn load in the prior day.

The model has the "Monte Carlo determined" adjusted load in one day reverting back somewhat (e.g., by 50% if B equals 0.5) toward the normal value of the prior day based on the Alpha parameter. Of course, at the same time the new days is also getting a Monte Carlo draw related to the weather in the new day.

The Monte Carlo process used to impact load in the model is done prior to unit commitment dispatch decisions for that week. Such an approach assumes that plant operators have somewhat decent weekly weather forecasts when they make their unit commitment decisions. Within each week, generation units are committed and dispatched as if they have perfect foresight of stochastic load values for that week. Figures N.8 and N.9 illustrate monthly load volatility in graphs of the 100 iterations of monthly load for FY 2009 for the East and West Control areas.

Figure N.8 – PacifiCorp East Monthly Load Iterations

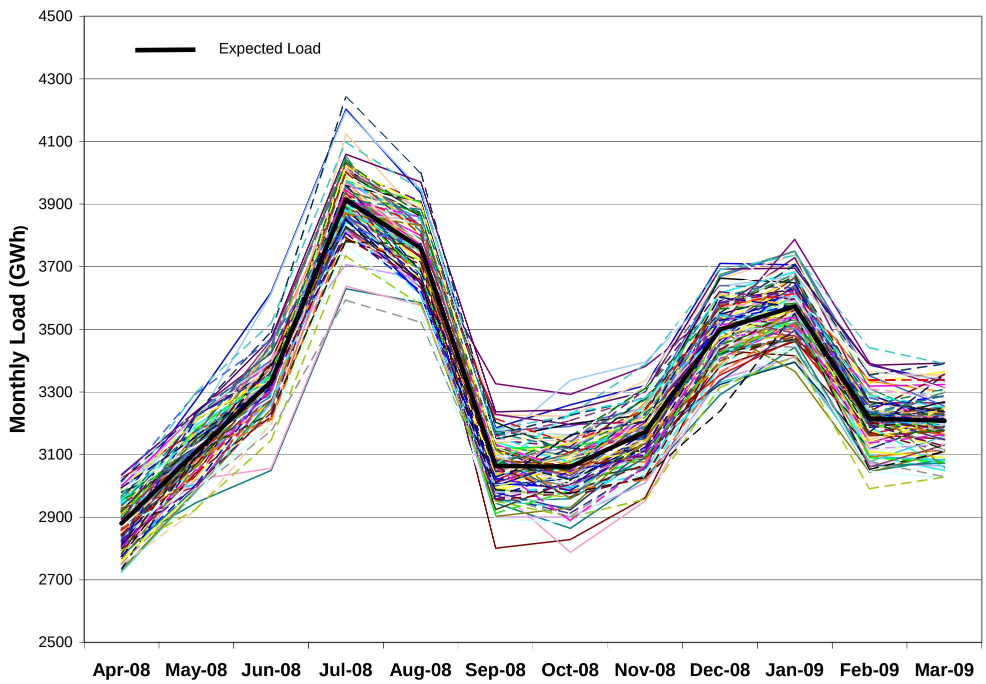
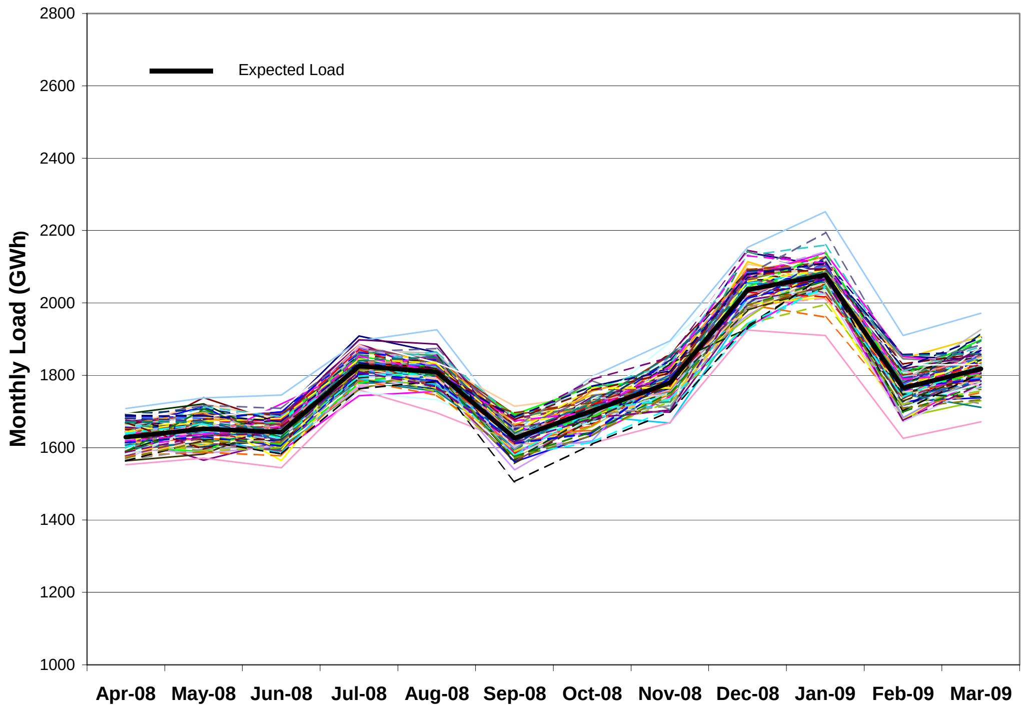


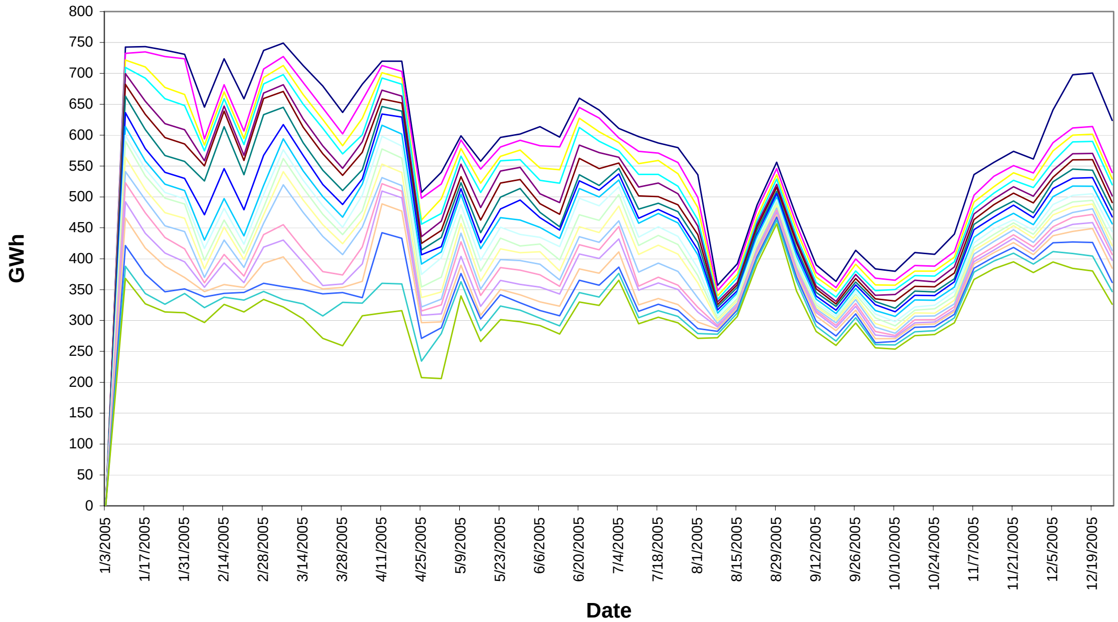
Figure N.9 – PacifiCorp West Monthly Load Iterations



<u>Hydroelectric Generation Volatility</u>

Based on historic data and expected regulatory requirements, PacifiCorp has developed hydroelectric generation forecasts for its owned and contracted units under varying levels of precipitation. PacifiCorp layered on top of that the probability of occurrence of each level of precipitation and developed data on weekly hydroelectric generation for the Western area under various levels of exceedence. (See Figure N.10)

Figure N.10 – PacifiCorp West Hydroelectric Generation by Percent Exceedence



<u>Forced Outage Rates on Supply Resources</u>
The model was run for 100 iterations for each year. Monte Carlo draws determine if a resource was on forced outage or not. If a unit has an expected forced outage rate of, for example, 5%, then the average outage hours for that unit over the 100 iterations is 5% of the time. However, any individual iteration could have an outage rate for that iteration for the year of greater or less than 5%. The Monte Carlo draws are designed such that over a large number of random draws of unit outage, statistically one would expect the average hours of a unit being forced out during a year to be 5%. However, statistically it is possible that over 100 iterations the average outage rate is slightly above or below the 5% number.

Modeling Approach
In order to perform this study, it is necessary to run the stochastic analysis at several different levels of supply reserve. As such, additional supplies need to be added at the margin in order to move the supply reserve level from one level to a higher level of reserve. The resource used to incrementally increase planning margin needs to be (a) highly reliable as a supply source and (b) relatively low cost to acquire since it will likely used at a very low capacity factor. While there are numerous supply technologies available for increasing supply, the reasonable supply unit to use for this purpose is a simple-cycle combustion turbine (SCCT).

The assumption used in this study is that the capital cost of the SCCT is $480/kW. Assuming a fixed charge rate of 15% to take into account capital costs, depreciation, income taxes, property taxes, insurance and fixed O&M. When distributed over the life of the plan, an annual rate of $72/kw/yr results.

In the first model run, the objective is to find the amount of resource additions for each side that produce the same amount of normalized expected unserved energy for each control area. This balanced condition where there is EUE and the LOLP is worse than the industry standard of 1 day in 10, is the starting point for the study. For the next model run, the planning margin is increased by 2% for each control area which will theoretically maintain that balanced condition while raising the system planning margin 2%. A 2% increase in the East is equivalent to 140MWs while a 2% increase in the West is equal to and addition of 60 MWs. This incremental addition method is continued until a range of planning margins are tested whose results include the industry standard reliability measure of 1 day in 10 for each control areas LOLP.

Calculating Reserve Margin – The "Counting" Issue

The most common method of calculating planning reserve margin at a utility uses the following equation (all units are MWs):

$$\frac{[(\text{Resources} + \text{Purchases}) - (\text{Peak Load} + \text{Sales})]}{(\text{Peak Load} + \text{Sales})}$$

Digging into this calculation and applying it to PacifiCorp's system raises interesting issues, which are important to consider when comparing the results of this study with other planning margin studies.

Peak Load

Peak load is generally the needle peak load of the control area. Since PacifiCorp consists of two interconnected control areas, the reserve margins may be separately calculated for the West on the winter peak and on the East in the summer peak hour. Or, the planning margin may be represented on a system level by finding the system peak hour and corresponding resources on that hour. PacifiCorp has chosen to report reserve margin on the system peak hour. The hour of the system coincident peak has a lower load in each of the control areas than both area's non-coincident needle peak, and the reserve margin when calculated on this hour will thus appear larger due to a similar set of resources being compared to a smaller denominator.

Resources

The maximum capacity (nameplate) of thermal stations is included in the calculation. For hydro resources, this is less straightforward. Some utilities use maximum capacity; while others use some derate from maximum capacity or even capacity under critical water conditions. For PacifiCorp calculations, a maximum capacity value was used after adjusting for operational and relicensing issues. Wind turbines are assumed to contribute 20% of their capacity value toward peak hour planning. Interruptible loads and demand side management programs are included as resources.

WECC Reserve Requirements

The WECC operating reserve requirement is currently the greater of the sum of 7% of control area load served by thermal generation plus 5% of control area load served by hydroelectric generation, or the control area's most severe single contingency. In either of these cases, at least half of that reserve must be spinning reserve.

Following these reserve requirements would mean that load serving entities (LSE) would be required to shed load if reserve levels fell below the reserve requirement. Control areas that are party to the WECC Reliability Management System agreement (RMS) and that violate minimum reserve obligation requirements are subject to monetary sanctions and other penalties. PacifiCorp is a signatory to the WECC RMS agreement and will not plan to violate the reserve requirements.

Limitations

As with any modeling representation of system dispatch, there are limitations to this study. The topology for the model condenses the system into two bubbles, which creates an imperfect representation of transmission constraints between sub regions and markets, which is better captured in the IRP model with 18 bubbles. The tradeoff in transmission detail for manageable runtime was considered valid due to the number of runs required for reliability results.

Resource additions were limited to SCCTs of 140MW capacity in the East (equates to 2% East planning margin) and 60 MWs in the West (equates to 2% margin). This assumption leads to the addition of over 1,000MW of SCCTs added to the system in the test year to meet the 1 in 10 reliability planning margin. Although this amount of SCCTs may not seem to be the typical resource to add in this magnitude, it is a simplified modeling assumption, which keeps portfolio building out of the scope. These resources are not meant to represent the actual portfolio planning process but rather to add consistent capacity type and size for each study case. The 2004 Integrated Resource Plan will address the topic of resource selection and appropriate choices whereas this study produces results relative to similar portfolios.

Results

Tables N.8 through N.10 provide detail on model results for the West and East areas for the system peak obligation hour.

Table N.8 – East LOLP Results Summary at Peak System Demand Hour

PacifiCorp East

Case	**Loss of Load Days per 10 years**	**Expected Unserved Energy** MWh	**EUE as a % of Total Load**	**Total Obligations** (Load + Sales) MW	**Total Resources** (Existing Resources + Purchases + New Additions) MW	**Planning Margin**
1	4.2	2,616	0.0087%	7,102	8,019	12.90%
2	3.1	1,827	0.0061%	7,102	8,089	13.89%
3	2.2	1,276	0.0042%	7,102	8,159	14.88%
4	1.7	918	0.0031%	7,102	8,229	15.86%
5	1.2	661	0.0022%	7,102	8,299	16.85%
6	0.9	451	0.0015%	7,102	8,369	17.83%
7	0.7	308	0.0010%	7,102	8,439	18.82%
8	0.5	186	0.0006%	7,102	8,509	19.80%
9	0.3	112	0.0004%	7,102	8,579	20.79%
10	0.2	61	0.0002%	7,102	8,649	21.77%
11	0.1	33	0.0001%	7,102	8,719	22.76%

Table N.9 – West LOLP Results Summary at Peak System Demand Hour

PacifiCorp West

Case	Loss of Load Days per 10 years	Expected Unserved Energy MWh	EUE as a % of Total Load	Total Obligations (Load + Sales) MW	Total Resources (Existing Resources + Purchases + New Additions) MW	Planning Margin
1	3.4	846	0.0041%	3,409	3,867	13.44%
2	2.7	634	0.0031%	3,409	3,897	14.32%
3	2.1	475	0.0023%	3,409	3,927	15.20%
4	1.6	345	0.0017%	3,409	3,957	16.08%
5	1.2	251	0.0012%	3,409	3,987	16.96%
6	0.9	191	0.0009%	3,409	4,017	17.84%
7	0.7	145	0.0007%	3,409	4,047	18.72%
8	0.6	108	0.0005%	3,409	4,077	19.60%
9	0.4	81	0.0004%	3,409	4,107	20.48%
10	0.4	61	0.0003%	3,409	4,137	21.36%
11	0.3	45	0.0002%	3,409	4,167	22.24%

Table N.10 – System LOLP Results Summary at Peak System Demand Hour

PacifiCorp System

Case	Total Obligations (Load + Sales) MW	Total Resources (Existing Resources + Purchases + New Additions) MW	Planning Margin
1	10,511	11,886	13.08%
2	10,511	11,986	14.03%
3	10,511	12,086	14.98%
4	10,511	12,186	15.93%
5	10,511	12,286	16.88%
6	10,511	12,386	17.84%
7	10,511	12,486	18.79%
8	10,511	12,586	19.74%
9	10,511	12,686	20.69%
10	10,511	12,786	21.64%
11	10,511	12,886	22.59%

Loss of Load Days In Ten With Increasing Planning Margin

Figure N.11 and N.12 show the expected loss of load days in 10 years for the range of reserve levels studied for the East and West control areas.

Figure N.11 – Loss of Load Days in 10 Years – East

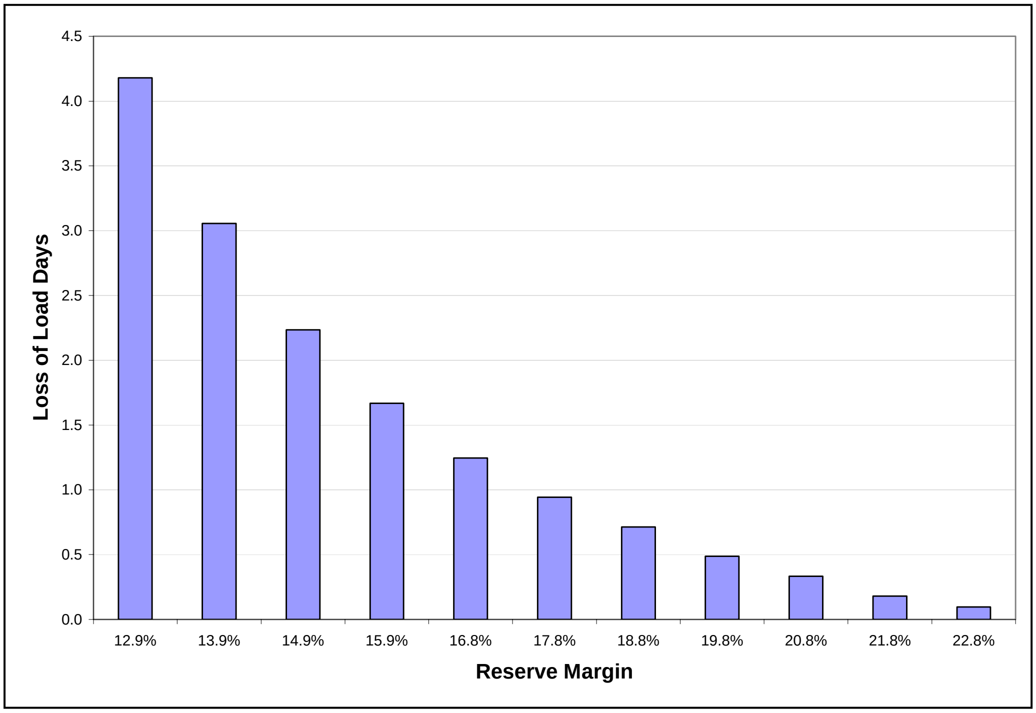
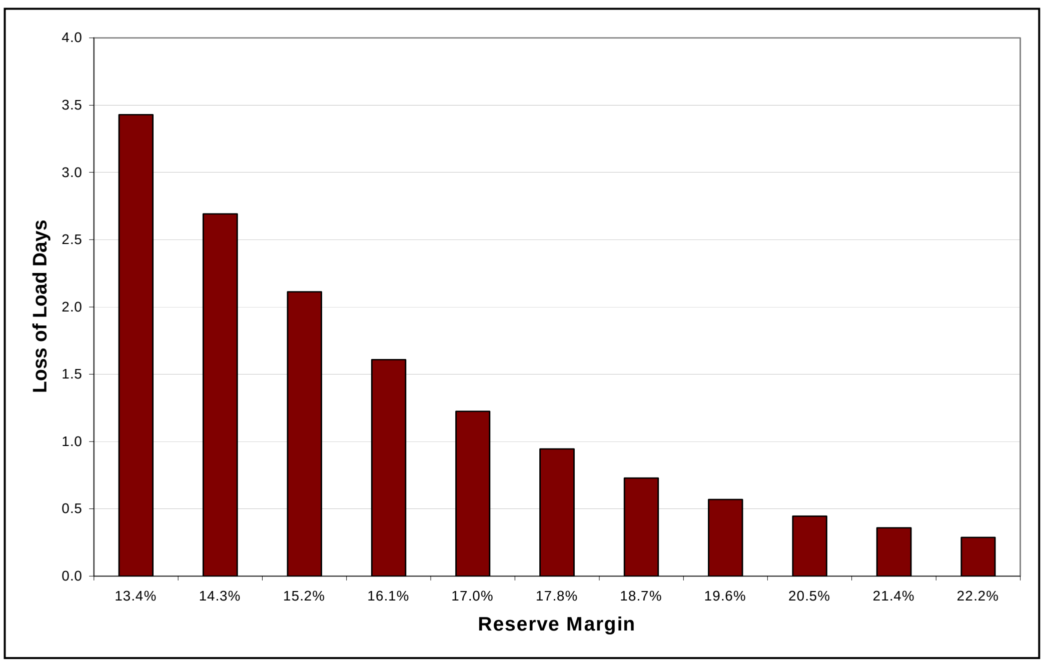


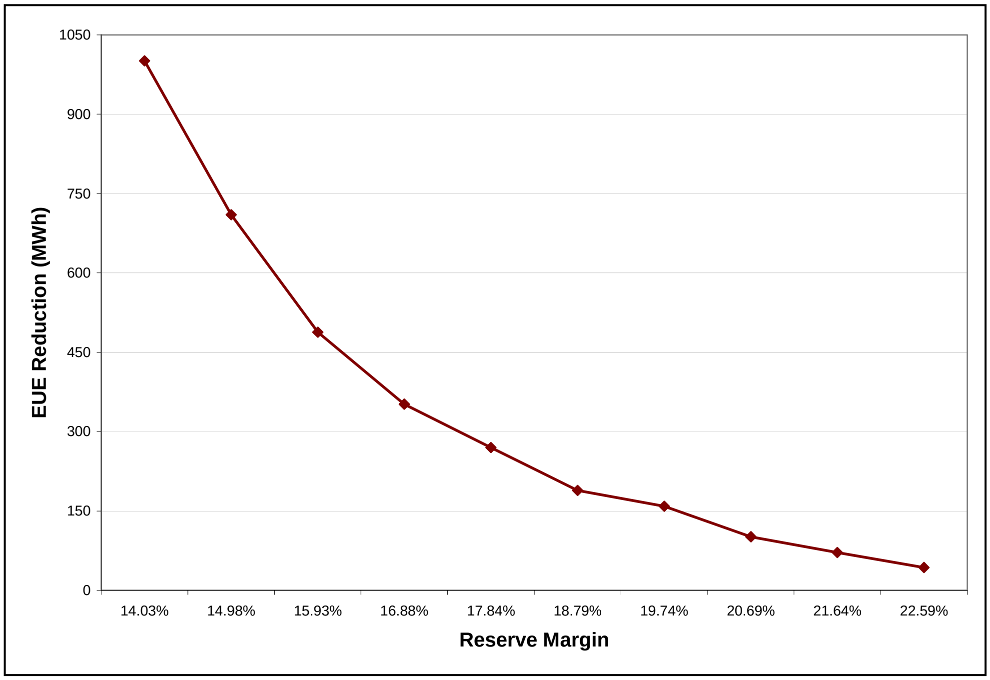
Figure N.12 – Loss of Load Days in 10 Years - West



Expected Unserved Energy With Increasing Planning Margin

Figure N.13 shows the EUE for the total system over the range of planning levels studied.

Figure N.13 – Expected Unserved Energy Versus Planning Reserve Margin – System



Cost of Reducing Expected Unserved Energy

Figures N.14 and N.15 portray the cumulative cost per year for increasing the planning margin by region, as well as the associated impact on the number of Loss of Load Days. The cumulative cost is the annual fixed carrying cost of the SCCTs including a fixed charge rate of 15% to take into account capital costs, depreciation, income taxes, property taxes, insurance and fixed O&M added to move from one level of reserve to the next. When distributed over the life of the plan, an annual rate of $72/kw/yr results. The analysis does not suggest the cost of decreasing unserved energy can be simply equated to the capital costs of the additional installed SCCTs. Rather those costs are merely illustrative of the cost of increasing the planning reserve margin, and if isolated would ignore the benefits of additional reserve margin, such as additional revenues, system flexibility, etc. Further, the appropriate planning margin may be reached through various demand and supply side measures via a systematic assessment like PacifiCorp's integrated resource planning process.

Figure N.14 – Cost of Reducing Loss of Load Days in 10 Years – East

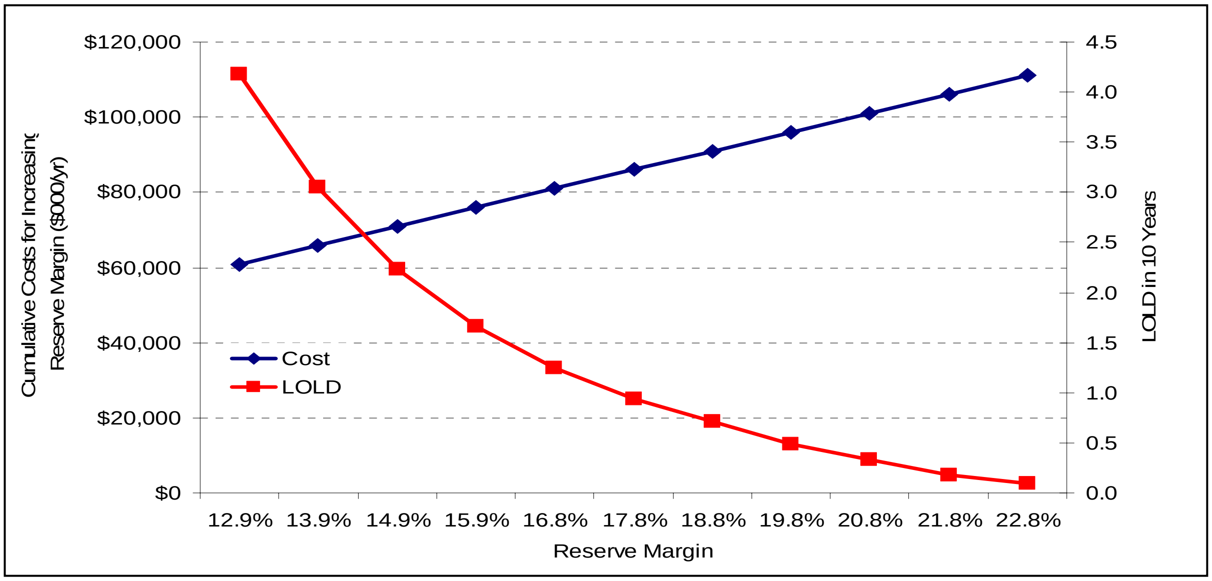
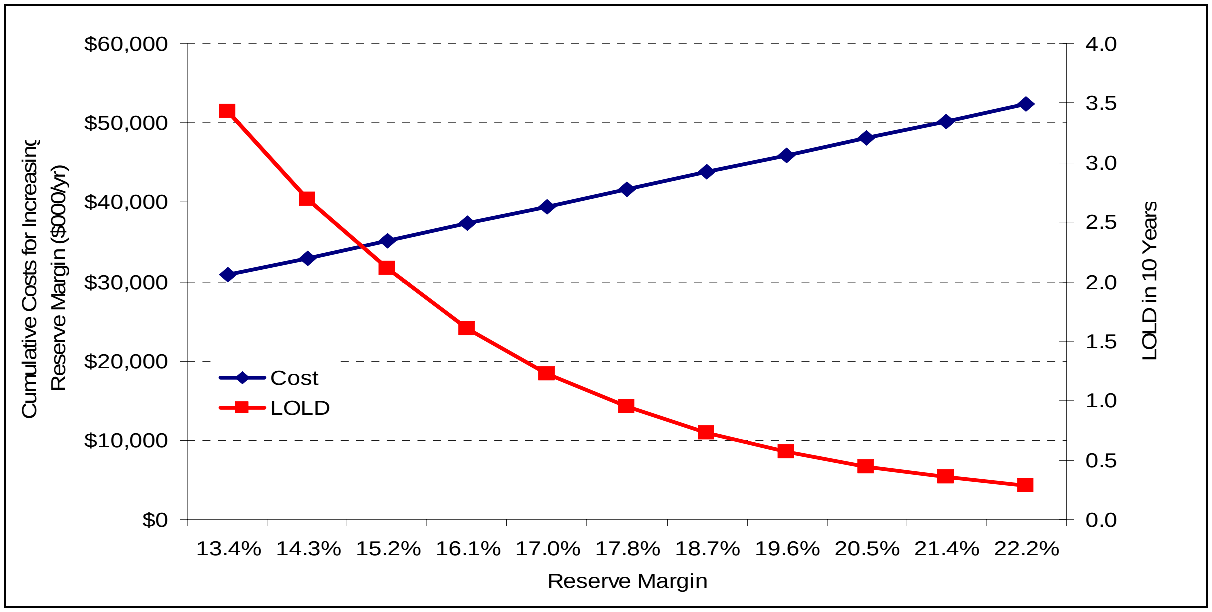


Figure N.15 – Cost of Reducing Loss of Load Days in 10 Years – West

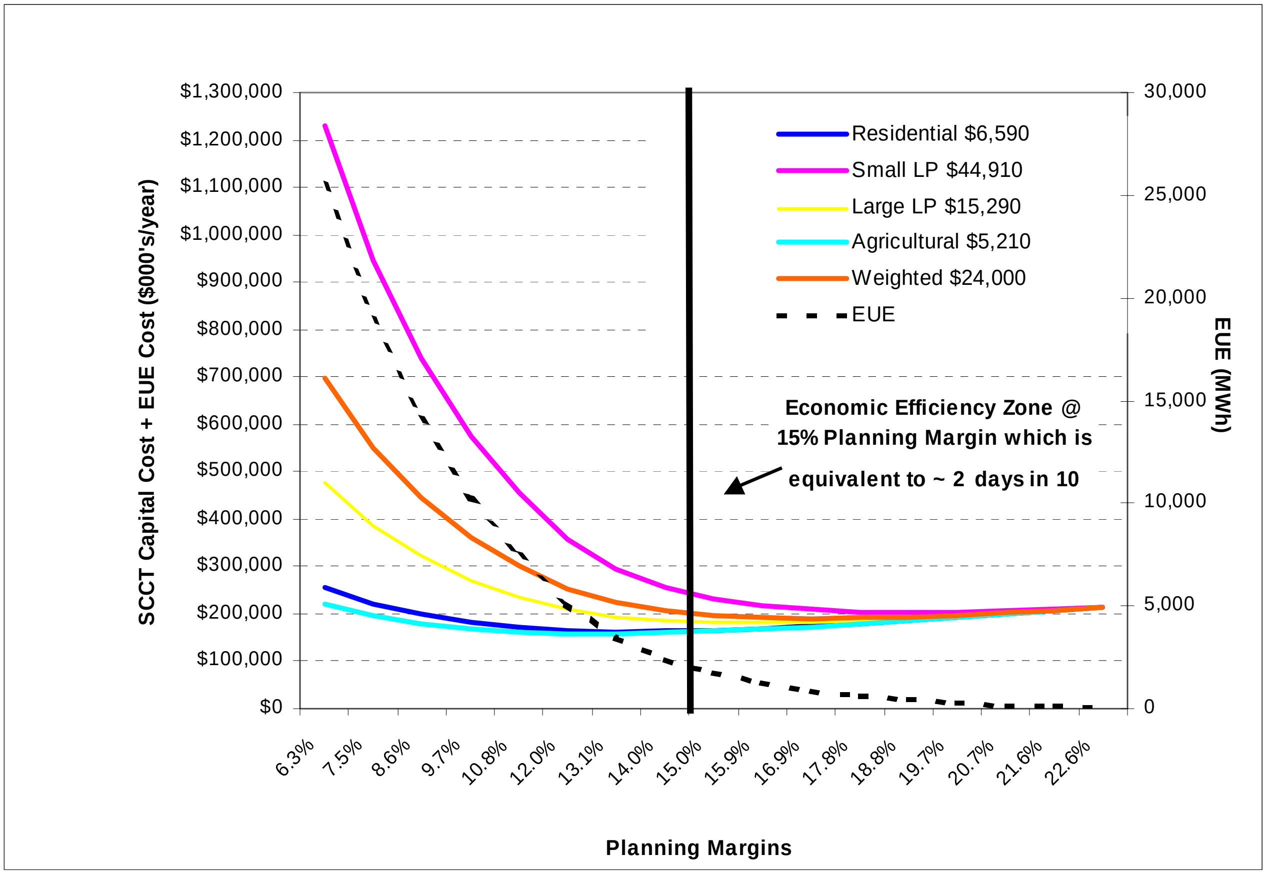


"Bathtub Chart"

There is also potential for large costs incurred by a utility for having insufficient resources to meet demand. Without some planning margin cushion, the amount of EUE for the system is much greater and the cost to purchase generation on the market during these emergencies as well as paying any penalties associated with not meeting reserve requirements can be high.

The illustration of decreasing costs of unserved energy as the amount of system resources increase compared to the increase in levelized capital expenses from additional resources is called a "Bathtub Chart". Figure N.16 illustrates the large range of cost tradeoffs for planning margin levels ranging from 6.3% up to 22.6% with high costs at the lower planning margin level which decrease and stabilize at the mid range and increase at the high planning margin level. Since the actual cost of covering demand during emergencies and paying fines for violating reserve requirements is unknown, a range of estimates for costs according to customer segment were tested. Estimates for the costs in $/MWh of EUE by customer type range from $5,210/MWh for agricultural customers to $44,910/MWh for small commercial customers. [40]

Figure N.16 – "Bathtub Chart" Capital and Outage Costs vs. Planning Margin



The plot shows the high costs of not meeting load with planning margins from 6.3% to 14% that level off between 14 and 15% planning margin until the increased cost of additional capital outweighs the costs from experiencing less EUE and the curve starts to climb up slightly again. As shown in the plot, there is an economic efficiency zone where the total costs (capital plus cost of EUE) transition from decreasing with planning margin to increasing with planning margin.

[40] Estimates for cost of EUE by customer segment referenced from PG&E cost of unserved energy results within the following study. Cost-Benefit Analysis of Power System Reliability: Determination of Interruption Costs, EPRI EL-6791, Volume 1, April 1990.

This point is achieved at a slightly different planning margin for each customer segment but when considered on a whole, 15% is representative of the bottom of the curve for the system.

Study Summary

The analysis indicates that when measuring resource adequacy at the system peak obligation, a planning margin of approximately 18% system wide would provide an expected probability of outage of one day (24 hours) in 10 years. While increasing the planning margin would lower the LOLP and provide even greater system reliability, it would result in increased costs for acquiring additional resources. A balance between reliability and cost tradeoffs is achieved at a 15% planning margin with a 2 in 10 LOLP.

Study Conclusions

The study results can be used to guide the decision for the appropriate level of planning reserve margin for the system and each control area based on the level of reliability desired for the costs associated with that level of reliability. Achieving a 1 in 10 year LOLP is a common industry standard threshold; however, there is no resource adequacy criteria based on LOLP for the WECC at this time.

In light of the cost-to-risk tradeoff analysis, using the 2 in 10 level seems to be the prudent option for our customers. From this analysis, we see that the cost tradeoff of setting a planning margin level above the 15% level doesn't provide a significant increase to system reliability but does come at a significantly higher cost to the company and customers. Taking all these points into consideration, PacifiCorp has decided to use 15% as the system wide planning margin for the 2004 IRP.

CONCLUSIONS AND RECOMMENDATIONS

PacifiCorp's long-term resource planning strategy for ensuring resource adequacy has evolved through the past few years beginning with the 2003 IRP and the 15% system wide planning margin. After expanding on that idea but taking a system specific approach which considered the load and resource balance techniques used for short term planning, the strategy was seen as more in line with actual operations and system constraints. The next step was to incorporate all the uncertainties of variables that impact long term planning into the process through use of a stochastic dispatch of the system and a review of system reliability through a range of planning margins. This current method incorporates all the benefits of a system specific approach with stochastic dispatch and applies to a long-term analytical review of system operations.

There are many regional efforts underway to develop a greater understanding of resource adequacy issues in the WECC region but until these efforts result in voluntary guidelines or mandated planning standards with regional information sharing, PacifiCorp will continue to optimize their planning strategy through stochastic modeling of their system to determine the optimum mix and amount of resources needed to:

- Meet load and operating reserve requirements
- Avoid physical short exposure to markets
- Ensure safe, reliable, low cost energy for the consumer

Results from Henwood's stochastic system study indicate that a planning margin level of 15% in the East and West control areas will provide the level of reliability needed to meet these goals.

APPENDIX O – REVENUE REQUIREMENT METHODOLOGY

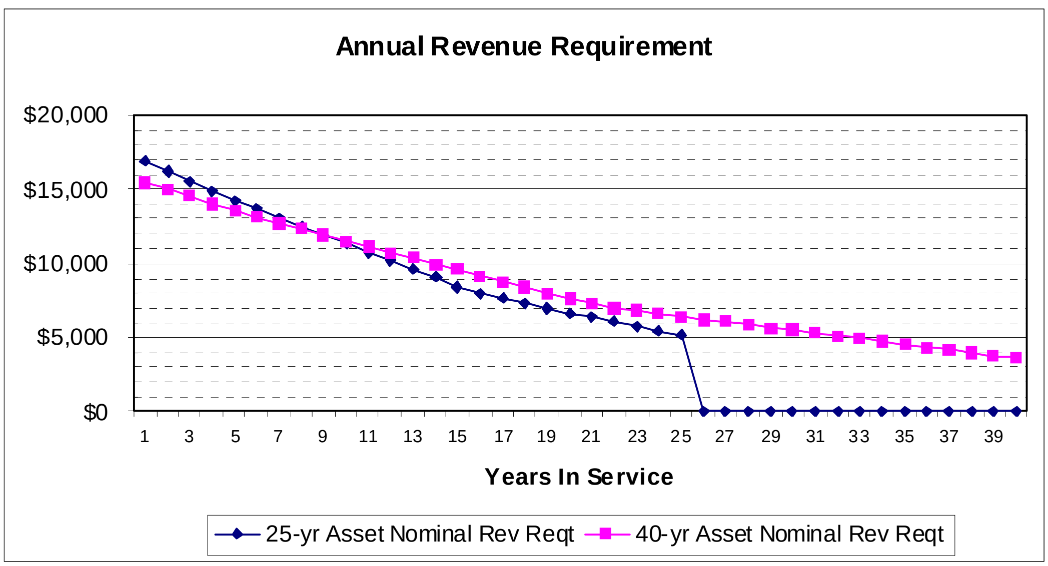
INTRODUCTION

PacifiCorp's IRP calculates and compares the revenue requirement of potential future resources to determine the best set of resources to meet future load projections. The IRP financial analysis includes both a variable and a fixed component of revenue requirement. The variable component includes total company fuel, variable O&M, spot market purchases and sales, start-up costs and the variable cost of purchase contracts. The fixed component includes DSM costs, incremental fixed O&M and the real levelized revenue requirement of new generation and transmission capital. This section will address the need for a real levelized capital revenue requirement as well as the calculation and application to IRP analysis.

NOMINAL CAPITAL REVENUE REQUIREMENT

Traditional capital revenue requirement is largest at the beginning of the asset life and declines over time as ratebase is depreciated. Capital revenue requirement includes depreciation expense, return on ratebase, income taxes and property taxes. Figure O.1 depicts the traditional nominal capital revenue requirements for a $100,000 asset with a 40-year depreciation life and for a $100,000 asset with a 25-year depreciation life.

Figure O.1 – Capital Revenue Requirements

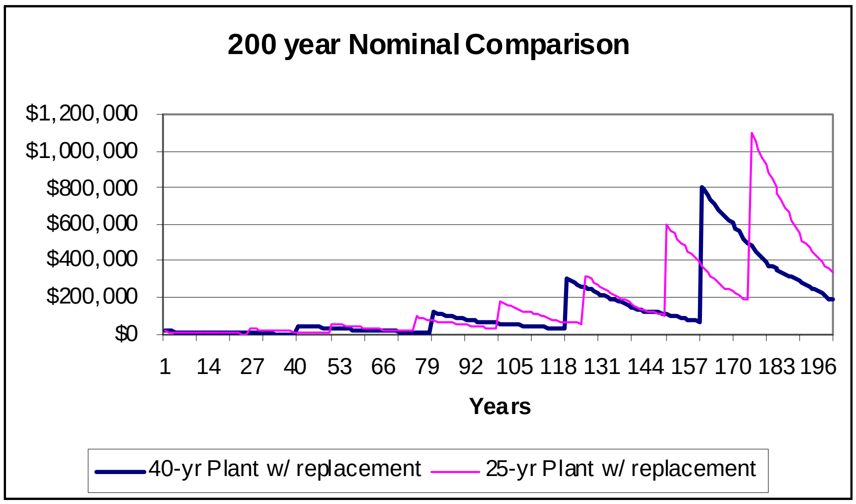


<u>Nominal Revenue Requirements Inadequate for Comparison</u>

Nominal capital revenue requirement is limited in its ability to adequately compare one type of resource asset against another. This is particularly true when the resources being compared have lives of different lengths, as depicted in the above example or if the resources are placed in service in different years. An analysis mismatch occurs unless an adjustment for end-life effects is made.

Another alternative, although not practical in this case, is to extend the analysis period to a length of time that results in the "least common denominator" analysis period. One could illustrate this point with an extreme example. It would take a 200-year analysis to make an equivalent comparison between the 25-year asset and a 40-year asset. The "least common denominator" analysis period would result in eight 25-year assets and five 40-year assets so that the analysis ended with the end-life of both assets. Figure O.2 shows a full 200 years of nominal revenue requirements for a series of 40-year and 25-year assets. For the purposes of this example, the Present Value of Revenue Requirements (PVRR) of both assets is exactly the same. Therefore, if all else were equal in this example, one would be indifferent over this 200-year analysis period between owning a series of 25-year resources or owning a series of 40-year resources.

Figure O.2 – 200 Year Nominal Comparison



Compiling a 200-year analysis is not practical, but it does illustrate a point. If one is indifferent between assets when considering an "equivalent" analysis period, then what are the results one gets when looking at a more practical analysis period, say 20 years, as is used in this IRP. Figure O.3 shows the cumulative PVRR of the above revenue requirements used in Figure O.2. (Cumulative PVRR is derived by taking the present value of each year's revenue requirement and adding it to the sum of the previous years' present value of revenue requirement; all discounted to a common time.) Only the results of the first 45 years are shown in order to highlight the earlier years. Over an extended analysis period (200 years), the PVRR of both assets is the same.

Figure O.3 – 45 Year Cumulative PVRR - Nominal

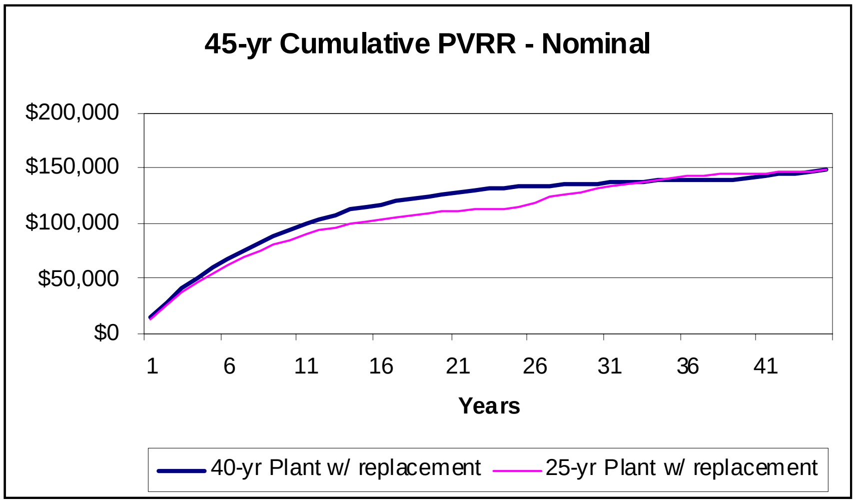


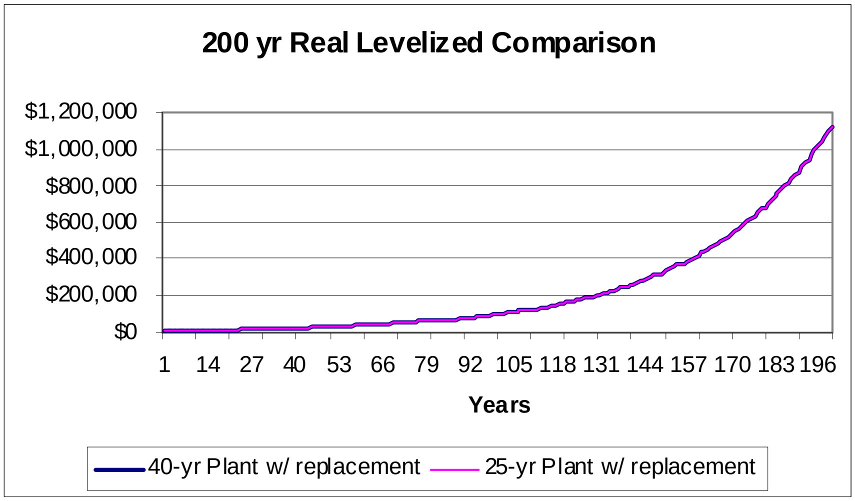
Figure O.3 clearly illustrates the problem with using nominal revenue requirements for comparing different types of resources. By definition, these assets were valued such that one should be indifferent. However, as can be seen, depending on the length of the analysis period, the nominal revenue requirement has created a valuation gap between the 40-year asset and the 25-year asset's revenue requirement. This could lead to misleading conclusions regarding the comparative cost of one resource versus another. Nominal revenue requirements, without some kind of end-effects adjustment, could result in incorrect analysis findings.

End-effect adjustment calculations can be challenging as well. For example, within a 20-year analysis period, what is the proper adjustment to a 40-year asset and a 25-year asset's cost that will place the analysis on equal footing? Should the adjustment be made to all years, or just the last year? Should the net asset value come into play, or should market valuations determine the adjustment? The answers would vary, as there are many methodologies that could be employed to calculate the end-effect adjustment. There is an easier approach that allows for comparative analysis between resource options. It consists of utilizing real levelized capital revenue requirement.

REAL LEVELIZED REVENUE REQUIREMENT

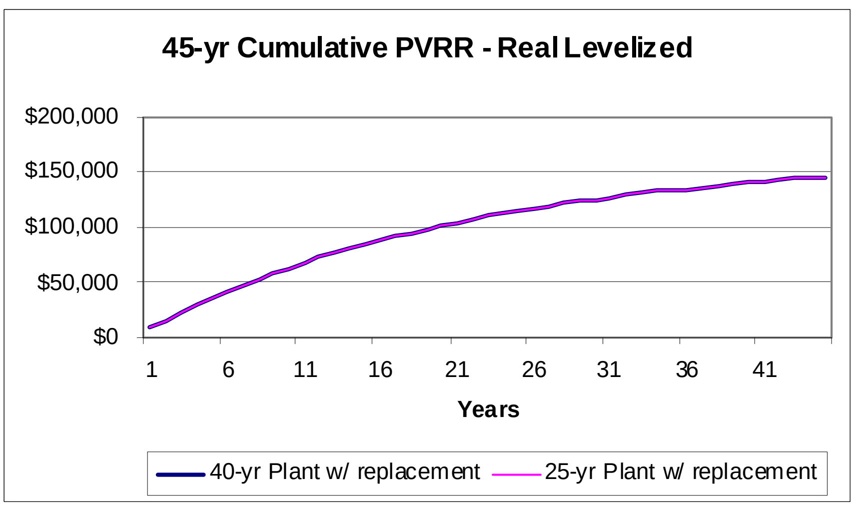
Real levelized revenue requirement is a methodology for converting the nominal year by year revenue requirement into a revenue requirement starting value, that when escalated over the same time period, will result in a revenue requirement projection that has the same present value as the nominal year by year revenue requirement. The shape of a real levelized revenue requirement is that it starts out lower in the initial year and increases at the rate of inflation. Unlike nominal revenue requirement projections, when a resource is replaced at the end of its initial life, the revenue requirement does not take a huge jump, but continues at the rate of inflation. This coincides with the projected revenue requirements that would be calculated for a new plant being constructed at the then escalated cost. An explanation of how real levelized revenue requirements are calculated is addressed in a later section. Figure O.4 shows the real levelized revenue requirement for the same two assets that were shown in Figure O.2.

Figure O.4 – 200 Year Real Levelized Comparison



Because Figure O.4 uses the same assets as Figure O.2, the PVRR of the revenue requirements are the same for both assets; hence the real levelized revenue requirement values for each resource are the same each year. As mentioned earlier, the replacement of the resources throughout time does not create huge jumps in revenue requirements. Figure O.5 is the same representation as Figure O.1, except that here again, the results are presented using real levelized revenue requirements. One can see that it doesn't matter how long the analysis period is, the comparative revenue requirement valuation is the same at any point in time.

Figure O.5 – 45 Year Cumulative PVRR – Real Levelized



So far, the two resources shown have been placed in service on the same date and have been priced to come to the same PVRR over an "equivalent" extended analysis period. This has been solely for the purpose of creating a case that shows that assets of equivalent cost should reflect that equivalent cost, regardless of how long the analysis period is. Real levelized revenue requirements provide such a case. The advantage of using real levelized revenue requirements is also extended to an analysis that compares various resources with various lives and various in-service dates. Real levelized revenue requirements will capture the comparative economic costs with respect to one set of resources being compared against another, without the need for end-effects adjustments.

Comparison to Market Purchases

The year by year nominal capital revenue requirement in Figure O.1 shows the front-end loaded revenue requirement for capital investment. How does this compare with the alternative of market purchases? Any analysis period short of a full asset life-cycle analysis will overstate the capital revenue requirements in the early years, while leaving the lower cost later years out of the analysis. With the IRP utilizing a 20-year analysis period, using nominal revenue requirements for resource capital will overstate the comparative cost of long-lived resources.

Restating the issue a different way, consider two groups of customers in a rising market price environment. Customer Group A will get to use and pay for a 40-year resource during the analysis period, say, the first 15 years, and Customer Group B will get to use and pay for the resource during the remaining plant life, or 25 years. Without some kind of adjustment, traditional or nominal revenue requirements would cause Group A to pay all the higher cost years, when market price is lower, while Group B would get to pay for all the lower cost years when market price is higher. This is hardly a fair allocation of resource costs among Customer Groups A and B when comparing the resource cost to market purchases.

Absent 20/20 foresight, any analysis methodology will have its challenges; however, utilizing real revenue requirement for capital is an improvement over nominal revenue requirements for comparing resource alternatives with market purchases when the analysis period is shorter than the life of the resource being considered.

Real Levelized Revenue Requirements Calculation

Table O.1 shows an example of how real levelized revenue requirements are calculated. The example shows an asset with a 15-year life.

- The present value of the nominal revenue requirements serves as a starting point.
- A “real” discount rate is then calculated by removing the inflation component from the discount rate.
- This real discount rate is used to calculate a levelized payment from the present value of the nominal revenue requirements…hence the name “real levelized.”
- The effects of inflation are added back in by escalating the real levelized payment each year by the inflation rate.
- The present value of the escalated real levelized revenue requirements is equal to the present value of the nominal revenue requirements.

Table O.1 – Real Levelized Capital Revenue Requirement Calculation Example

Year	Nominal	Real Levelized
1	$19,386	$12,008
2	$18,233	$12,309
3	$16,977	$12,616
4	$15,872	$12,932
5	$14,886	$13,255
6	$13,997	$13,586
7	$13,170	$13,926
8	$12,362	$14,274
9	$11,553	$14,631
10	$10,745	$14,997
11	$10,013	$15,372
12	$9,432	$15,756
13	$8,928	$16,150
14	$8,423	$16,554
15	$7,919	$16,968
Present Value @ 7.5%	$122,612	$122,612

Discount Rate = 7.5%
Inflation Rate = 2.5%
Real Discount Rate = (1+discount rate) / (1+inflation rate) - 1
= (1+ .075) / (1+.025) - 1
= 4.878%

Formula for first year of real levelized revenue requirement
= -Pmt(real discount rate,asset life,PV nominal revenue requirement) x (1+inflation rate)
= -Pmt(.04878,15,122612) x (1.025)
= $12,008

Second and subsequent years' real levelized revenue requirement
= prior year real levelized revenue requirement x (1 + inflation rate)

SUMMARY AND CONCLUSION

The IRP financial analysis covers a 20-year forecast period. During this forecast period, the IRP is comparing the alternative resources available to determine the best overall solution to match resources with projected load. Because many of the potential resources have long economic lives of various lengths, which extend beyond the analysis period, appropriate methodologies must be used to capture the comparative costs of such capital-intensive investments.

Nominal capital revenue requirements consist of larger values in the earlier years and decline as ratebase is reduced by asset depreciation. If the asset's life extends beyond the analysis period, this front-end loading will cause an over valuation of the comparative revenue requirements. An end-effects adjustment could be made, but the value of those end-effects can be difficult to determine.

An alternative methodology, which is being used in the IRP, is to utilize a real levelized capital revenue requirement in the analyses. This eliminates the need for an end-effects adjustment, and provides a reasonable approach for comparing the revenue requirement of capital resources against each other and also against market purchase resources.

ACRONYMS

Acronym	**Description**
A/C	Air Conditioning
AEO	Annual Energy Outlook
AIR	Additional Information Requests
MWa	Average Megawatt
BACT	Best Achievable Control Technology
Bcf	Billions Cubic Feet
BPA	Bonneville Power Administration
C&T	Commercial and Trading (PacifiCorp) - Resource Planning included.
CCCT	Combined Cycle Combustion Turbine
CEM	1. Continuous Emission Monitor: Monitors used during emissions studies on electric plants. 2. Capacity Expansion Model: Linear Programming tool used during portfolio building process.
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CREPC	The Committee on Regional Electric Power Cooperation
CT	Combustion Turbine
DF	Duct Firing
DG	Distributed Generation
DOE	Department of Energy
DSM	Demand Side Management
EA	Environmental Assessment
EEAG	Energy Efficiency Advisory Group
EIA	Energy Information Administration
EIS	Environmental Impact Statement
ELCC	Effective Load Carrying Capability
ENS	Energy Not Served
ESA	Endangered Species Act
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOR	Forced Outage Rates
FGD	Flue Gas Desulfurization
GHG	Greenhouse gases
GJ	Giga Joules
Hg	Mercury
IC	Internal Combustion
IOU	Investor Owned Utility
IPC	Idaho Power Company
IPUC	Idaho Public Utilities Commission
IRP	Integrated Resource Plan
IRPAC	Integrated Resource Plan Advisory Council
kV	Kilovolt
kW	Kilowatt

Acronym	**Description**
kWh	Kilowatt Hour
LOLP	Loss Of Load Probability
LIWA	Low Income Weatherization Assistance
LSE	Load Serving Entity
MAF	Million Acre Feet
MidC	Mid-Columbia (Electricity trading hub; PacifiCorp Topology Bubble)
MMBtu	Million British Thermal Units
MW	Megawatt
MWa	Megawatt Average
MWh	Megawatt hour
NEEA	Northwest Energy Efficiency Alliance
NO_X	Nitrogen Oxides
NPV	Net Present Value
NWPCC	Northwest Power and Conservation Council
OPUC	Oregon Public Utility Commission
PM&E	Protection, Mitigation and Enhancement
PNW	The Pacific Northwest
PTC	Production Tax Credit
PURPA	Public Utilities Regulatory Policies Act
PV	1. Present Value 2. Palo Verde (Electricity trading hub; PacifiCorp Topology Bubble) 3. Photovoltaic
PVRR	Present Value of Revenue Requirements
QF	Qualifying Facility
psi	Pounds per square inch
RFP	Request For Proposal
RSAC	Regional State Advisory Committee
RTO	Regional Transmission Organization
SCCT	Single Cycle Combustion Turbine
SEC	Securities and Exchange Commission
SIC	Standard Industrial Classification
SMD-NOPR	Standard Market Design Notice of Proposed Rulemaking
SO_2	Sulfur Dioxide
SSG-WI	Seams Steering Group Western Interconnect
tcf	Trillion Cubic Feet
WACC	Weight Average Cost of Capital
WMain	West Main (Topology Bubble)
WRAT	Westwide Resource Assessment Team (Formed by CREPC)

GLOSSARY

Ancillary Services: Interconnected Operations Services identified by the Federal Energy Regulatory Commission (Order No. 888 issued April 24, 1996) as necessary to affect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff.

Antithetic Sampling: A sampling method used in Monte Carlo simulation techniques. The antithetic sampling method speeds up convergence of the sample mean for each of the stochastic variables simulated and reduces sample variance, which is a measure of the difference of the sample mean from the expected value. Antithetic sampling is a fairly common approach used to increase computational efficiency of Monte Carlo techniques.

Area Control Error (ACE): The instantaneous difference between actual and scheduled power interchange between two points, taking into account the effects of frequency bias.

Average Demand: The measure of the total energy load placed by customers on a system, divided by the time period over which the demands are incurred.

Base Load: The minimum amount of electric power required over a given period of time at a steady rate.

Best Available Control Technology (BACT): Emission control standard for each pollutant regulated under the Clean Air Act that requires advanced control systems and techniques. The determination of BACT takes into account energy, environmental, economic effects and other costs, and is applied on a case-by-case basis.

Bonneville Power Administration (BPA): A Federal power marketing agency that markets the power produced by the Federal Columbia River Power System (primarily federally-owned hydroelectric generation facilities) within the Pacific Northwest, and operates a vast network of federally-owned transmission facilities.

California-Oregon Border (COB): A trading point on the electric grid in the Northwest.

Call Option: The right to call ("buy") energy and capacity at specific rates at a defined strike price and date.

Capacity: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress. For purposes of the IRP, the capacity of a generating unit is the maximum load available for dispatch, subject to forced outages, at the discretion of the operator.

Clean Air Act (CAA): Federal legislation enacted to establish standards for the emission levels of various air pollutants. The CAA was last modified in 1990.

Clean Air Initiative (CAI): Internal PacifiCorp program to identify potential new emission control regulations and the cost impact resulting for such new requirements.

Clear Power Act (CPA): more stringent proposed legislation, with lower annual emission caps for SO_2 and mercury than CSA, and an emission cap for CO_2.

Clean Power Act (Jeffords Bill or CPA): more stringent proposed legislation, with lower annual emission caps for SO_2, NO_X, and mercury than CSI, and an emission cap for CO_2.

Clear Skies Initiative (CSI): Proposed legislation sponsored by the Bush Administration that reduces emission levels for SO_2, NO_X, and Hg from the current CAA and would establish cap and trade systems for NO_X and Hg. The Initiative does not include an emission cap for CO_2.

Coefficient of Variation: A relative measure of dispersion equal to the standard deviation divided by the mean.

Confidence Interval: A $(1-\alpha)100\%$ confidence interval for the mean is a set of two numbers from a random sample such that the probability of the true mean falling between the two numbers is $(1-\alpha)100\%$.

Congestion: Refers to restrictions on one or more transmission paths—such as insufficient capacity—that prevent the most economic dispatch of electricity to meet demand, or prevents physical delivery to the degree desired by market participants.

Contingency Reserves: An amount of spinning and non-spinning reserves sufficient to reduce area control error (ACE) to zero within ten minutes. The Western Electricity Coordinating Council sets the minimum requirements as 5% of Control Area Demand carried by hydroelectric generation, and 7% of the Control Area Demand carried by the thermal units. See Area Control Error.

Control Area: A geographical area reflecting an electrical system bounded by interconnection metering and telemetry equipment, for which a utility (1) controls generation for maintaining interchange schedules with other control areas, (2) contributes to frequency regulation, and (3) is obligated to meet operational standards as established by electric reliability regions (such as the WECC). PacifiCorp's system is composed of two control areas, both of which are modeled for the IRP.

Combined-cycle Combustion Turbine (CCCT): A electrical generation device powered by fossil fuel (natural gas), that combines a combustion turbine with a steam turbine to produce electrical generation.

Combined Heat and Power (CHP): The use of a single prime fuel source such as reciprocating engine or gas turbine to generate both electrical and thermal energy to optimize fuel efficiency. Also known as cogeneration.

Continuous Emission Monitor (CEM): An air emissions monitoring system installed in a smokestack or other emission source that is designed for continuous operations.

Correlation (Coefficient): A statistic, bounded at -1 and 1, which measures the degree to which two variables are linearly related. In the context of PacifiCorp's stochastic simulations, correlation values are used to adjust the initial random draws for each variable in order to account for the correlations in short-term and long-term stochastic movements.

Decrement Value: The reduction in system production costs due to the load reduction associated with a Class 2 DSM decrement. The decrement value for a given year is determined by subtracting the revenue requirement of a portfolio which includes a given DSM program from the revenue requirement of the same portfolio without the DSM program.

DOE: United States Department of Energy. The Federal agency that administers energy policies and programs.

DSM Decrement: A Megawatt amount corresponding to a reduction in load attributable to new Class 2 DSM programs.

Demand: The amount of electric power required at any specific point or points on a system. The requirement originates at the energy consuming equipment of the consumers.

Demand Forecast: An estimate of the level of energy or capacity that is likely to be needed at some time in the future.

Demand Side Management (DSM): Methods of managing electrical resources that affect use, rather than generation, of electricity, e.g., energy efficiency or load control measures.

Deterministic Simulation: A technique by which a prediction is calculated from a model based on a set of fixed inputs and model parameters. No randomness or uncertainty is assumed for the inputs and simulated prediction. (See Stochastic Modeling.)

Dynamic Allocation Factor: A cost or revenue allocation factor that is calculated using States' monthly energy usage and/or States' contribution to monthly system Coincident Peak.

Emissions: Refers to chemical compounds released from the burning of fossil fuels, including mercury (Hg); nitrogen oxides (NO_X); sulfur dioxide (SO_2), and carbon dioxide (CO_2).

Energy Information Administration (EIA): An agency of the U.S. DOE that collects energy industry statistics, conducts energy market analysis, and publishes reports for the Government and general public.

Energy Policy Act (EPACT): Federal legislation enacted in 1992 to encourage robust competition in wholesale electricity markets.

Energy Trust of Oregon (ETO): A trust created by Oregon's direct access legislation -- SB1149. The Trust receives funding from a public purpose charge included in retail electric rates, and administers funding of existing and new DSM and renewable generation programs and projects in Oregon for PacifiCorp's and Portland General Electric's customers in Oregon.

Environmental Protection Agency (EPA): A Federal agency that administers Federal environmental policies and legal requirements, including the Clean Air Act and amendments thereto.

Federal Columbia River Power System (FCRPS): The system of generation in the Pacific Northwest (primarily federally owned hydroelectric facilities) operated by the Corps of Engineers and the Bureau of Reclamation, and marketed by BPA.

Federal Energy Regulatory Commission (FERC): The federal regulatory agency responsible for interstate electric power transmission, the sale of electric power for resale and the licensing of hydroelectric plants.

Federal Power Act (FPA): 1935 Federal act establishing guidelines for federal regulation of public utilities engaging in interstate commerce of electricity. Among other things, provides for the re-licensing of hydro projects. See Appendix A.

Firm Transmission: Transmission service that may not be interrupted for any reason except during an emergency or when continued delivery of power is not possible.

Fiscal Year: PacifiCorp's Fiscal Year is from April 1 through March 31.

Forward Price: A predetermined price written in a forward contract for a commodity. For electricity markets, it represents the price that a party will pay today for electricity delivered at a future date.

Fuel Cell: A device that generates direct current electricity by means of an electrochemical process.

Gap, Load and Resource: The difference between a load forecast and available resources to meet the load.

Green Tags: A tradable commodity that represents the per-megawatt hour value of the environmental attributes for a particular renewable-electric generator. Green Tags have also been called tradable renewable certificates (TRC) or renewable energy credits.

Grid: The layout of the electrical transmission system or a synchronized transmission network.

Grid West: An independent, non-profit corporation that would manage certain operational functions of the regional transmission grid and plan for necessary expansion. Formerly called RTO West. Bylaws for Grid West were adopted by its member organizations on December 10, 2004. (See Regional Transmission Organization)

Heavy Load Hours (HLH): This refers to the time of day on a system that would be considered peak demand. Actual hours vary by individual power system. For IRP purposes the heavy load hours are 6 a.m. to 10 p.m., Monday through Saturday (6 X 16).

Heat Rate: A measure of generating station thermal efficiency, in units of Btu's per net kilowatt hour.

Integrated Gasification Combined Cycle (IGCC): Power generation technology that produces electrical power by combusting coal in an oxygen-starved environment to produce a low-Btu fuel gas, which is burned in a combined cycle combustion turbine.

Interruptible Demand: The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of system operator, remote tripping, or by action of the customer at the direct request of the system operator.

Light Load Hours (LLH): This refers to the time of day on a system that would be considered off-peak demand. Actual hours vary by individual power system. For IRP purposes, the light load hours are 10 p.m. to 6 a.m., Monday through Saturday, and all of Sunday (6X8 + 24 + Holidays.)

Load Factor: The ratio of average load to peak load during a specific period of time, expressed as a percent. The load factor indicates to what degree energy has been consumed compared to maximum demand or the utilization of units relative to total system capacity, average demand/peak demand.

Load Following: generally means generation responding to changes in load.

Load Management: The management of load patterns in order to better utilize the facilities of the system. Generally, load management attempts to shift load from peak use periods to other periods of the day or year.

Load Shape: The variation in the magnitude of the power load over a daily, weekly, monthly or annual period.

Long Asset Strategy: To serve resource needs primarily through generating assets, either owned or under cost-based contract. (See Short Asset Strategy).

Long Position: Having more resources than load (see "short position").

Megawatt (MW): Unit of electric power equal to one thousand kilowatts.

Megawatt-hour (MWh): A unit of electric energy, which is equivalent to one megawatt of power used for one hour.

Merchant Generators: Non-utility suppliers including cogenerators, small power producers, and independent power producers acquiring, developing and owning power plants and marketing their output.

Mid-Columbia (MidC): Trading hub for electricity located in central Washington near the mid-Columbia hydro projects.

Mill: A currency denomination equal to one-thousandth of a U.S. dollar or one-tenth of a cent.

Multi-State Process (MSP): In April 2002, PacifiCorp and interested parties from across the company's service area initiated an investigation into challenges faced by PacifiCorp as a multi-state utility. The parties entered into a MSP to develop and review possible solutions to those challenges.

National Marine Fisheries Service (NMFS): This Federal agency manages marine commerce, including harvest of ocean species and is responsible for implementation of the Endangered Species Act when it applies to species that inhabit the ocean, including anadromous salmon that populate the Columbia River system. NMFS is significantly involved in the operation of the FCRPS to protect threatened and endangered species.

Nominal Capital Revenue Requirement: Capital revenue requirement calculated by applying traditional ratemaking calculations. Nominal capital revenue requirement is largest when an asset is first placed in service and declines over time as rate base is depreciated. (See Real Levelized Revenue Requirement)

Nonfirm Transmission: Transmission service that may be interrupted in favor of Firm Transmission schedules or for other reasons.

Non-spinning Reserve: Off-line generating capacity that can be brought on-line to serve demand within a specified time (10 minutes in the case of the WECC requirement).

North American Electric Reliability Council (NERC): A national voluntary organization, founded in 1968, that provides standards for coordination in operating and planning a reliable and adequate electricity system.

Northwest Power Planning Council (NWPPC): A federal multi-state compact created by Congress as part of the 1980 Northwest Regional Power Planning Act. The intent was to give the citizens of Idaho, Montana, Oregon and Washington greater participation in decision making regarding electricity generation and wildlife management policies associated with the Columbia River Basin hydropower dams. The Council prepares an electric power plan for the Northwest and a fish and wildlife program for the Columbia River Basin.

Notice of Proposed Rulemaking (NOPR): A regulatory proposal issued in draft form by the Federal Energy Regulatory Commission, usually subject to comment and change before promulgated as a final rule.

NO_X SIP Call Trading Program: The NO_X State Implementation Plan Call Trading Program was established by the EPA in 1998 to address seasonal interstate transport of NO_X, and covered 22 states and the District of Columbia during the 2004 summer ozone season. The program targets large stationary sources of NO_X emissions, mostly electricity generating facilities, by requiring that the affected states revise their SIPs to achieve NO_X emission-reduction targets assigned by EPA for the ozone season, defined as May through September. Under the NO_X trading program, each allowance is equivalent to one short ton of NO_X emissions.

Off-peak: Refers to a period of relatively low demand on a utility's electrical system. (See LLH).

Operating reserve: Is defined as that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages, and local area protection.

Operating Margin: An amount of generation capacity required to cover uncertainties in generation availability and demand. The Hourly Operating Margin, as established by WECC, includes Contingency Reserves and Regulating Reserves.

Oregon Senate Bill 1149 (SB 1149): The Oregon legislation enacted in Oregon is commonly still referred to by its original Senate bill number: SB1149. This legislation provides for direct market access for commercial and industrial electric customers served by PacifiCorp and Portland General Electric in Oregon. It also requires these two electric utilities to collect from its Oregon retail customers a public purpose charge equal to 3% of revenues to support programs implemented by the Energy Trust of Oregon.

PacifiCorp East: PacifiCorp's eastern control area, covering its power system in Utah, Idaho, Wyoming (excluding the Jim Bridger Plant) and power plants and associated transmission in Arizona and Colorado.

PacifiCorp West: PacifiCorp's western control area, covering power system in Oregon, Washington and California, including the output of the Jim Bridger Plant (located in Wyoming) and PacifiCorp's share of Colstrip in Montana.

Paired-Difference Test: A statistical test used to determine whether the means of two groups, which have a shared dependence, differ from each other to a statistically significant degree.

PPM Energy, Inc.: An unregulated marketing affiliate of ScottishPower.

Palo Verde (PV): A trading point on the electric grid located near the Palo Verde nuclear generation facility in southern Arizona.

Paradigm Risks: For purposes of the IRP, Paradigm risks include those risks which cannot be reasonably represented by a number. Similarly, Paradigm risks do not vary according to a known statistical process. Paradigm risks are typically associated with large shifts in market structure or business practices, such as introduction of RTO and SMD.

PIRA: Stands for the PIRA Energy Group, an international consulting firm founded in 1976 that provides market intelligence, analysis, and price forecasting services.

Planned Resources: In the context of this IRP, Planned Resources are resources that PacifiCorp is firmly committed to acquire, and either is in the process of procuring the resource(s) or there is a solidly established historical pattern associated with the resource acquisition. Planned Resources are included in the Load and Resource (L&R) balance because they reflect decisions and/or acquisition processes that can be predicted with some degree of confidence.

Planning Margin: Represents the difference between expected annual peak capability and expected annual peak obligation, expressed as a percentage of the annual peak obligation. It is the long-term planner's tool to identify needs for additional resources so that Operations staff will have sufficient operating reserves in the future.

Portfolio: In the context of the IRP, a collection of new IRP resource options (along with existing and planned resources) designed to address PacifiCorp's expected short position.

Power Marketers: These are electricity market participants that buy and sell electricity as independent intermediaries.

Power Purchase Agreement (PPA): Shaped energy products, usually tied to an asset, that PacifiCorp considers purchases from a credit-worthy market participant.

Present Value of Revenue Requirements (PVRR): The sum of year-by-year revenue requirements, discounted at an after-tax cost of capital to a common date. The PVRR takes into account the time value of money such that different projections of costs of various timing and magnitude can be evaluated on a comparable basis. (See "WACC")

Primen: A consulting organization established in 2000 by the Electric Power Research Institute (EPRI) and Gas Technology Institute (GTI). Primen specializes in market studies and data for the electric and gas industries.

Profiled Wind: A wind resource modeled with a production shape reasonably representative of the resources expected physical output, e.g. without any associated firming or shaping provided by a third party.

Production Tax Credit (PTC): A federal tax credit for qualified renewable energy facilities, specified in Section 45 of the Internal Revenue Code. The PTC is equal to 1.5 cents (indexed for inflation) per kilowatt hour of electricity produced, and is available for five or ten years, depending on the type of renewable resource used.

Proxy Resource: In the context of the IRP, a modeled 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 RFP process.

Public Utilities Holding Company Act (PUHCA): Federal legislation designed to work in tandem with the FPA (see FPA). PUHCA and FPA of 1935 addressed issues that arose regarding electric holding companies. PUHCA is an act relating to the structure of utilities. It defines what a holding company is, how it is regulated, and limits the kinds of businesses that a holding company can engage in.

Public Utility Regulatory Policies Act of 1978 (PURPA): Federal legislation to promote independent resource development, including renewable resources and cogeneration, and to reduce utility reliance on imported oil (see Appendix A.)

Put Option: The right to put ("sell") energy and capacity at specific rates at a defined strike price.

Qualifying Facilities (QF): A designation created by the Public Utility Regulatory Policies Act (PURPA) of 1978 for non-utility power producers that meet certain operating, efficiency and fuel use standards set by the FERC.

Real Levelized Revenue Requirement: This is a methodology for converting the nominal year-by-year revenue requirement into a revenue requirement starting value that, when escalated over the same time period, will result in a revenue requirement projection that has the same present value as the nominal year-by-year revenue requirement (see PVRR.)

Regional Transmission Organization (RTO): An independent entity, advocated in FERC Order 2000, that coordinates regional transmission operations and planning for member organizations. RTOs are intended to increase transmission efficiency and facilitate the development of competitive wholesale markets.

Regulating Reserves: An amount of reserves required to maintain continuous balance of generation and load. The WECC regulating reserve requirement is 175 MW to control frequency to ACE tolerance.

Renewable Portfolio Standard (RPS): A regulation that requires electricity providers to include a minimum percentage of renewables in their electricity generation mix.

Resource and Market Planning Program (RAMPP): Previous PacifiCorp IRP study effort.

Restated Transmission Services Agreement (RTSA): Agreement with Idaho Power Company providing, among other things, up to plus or minus 100 MW of Dynamic Overlay Control Service, and bi-directional transfers of 104 MW of power and energy between PacifiCorp's Wyoming System and PacifiCorp's Utah System.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Scenario Risks: In the IRP, Scenario risks include those risks which can be reasonably represented by a number (parameter). However, parameter variability cannot reasonably be explained by a known statistical process. For purposes of evaluation, Scenario risk parameters are manually adjusted (or stressed) to test the impact of their variation upon modeling results. Such testing is typically used to evaluate an abrupt change in risk factors (e.g. changes in carbon taxes).

Shaped-products: PPA agreements, which try to match the purchased energy to PacifiCorp's load requirements.

Short Asset Strategy: To serve resource needs primarily through market purchases. (See also Long Asset Strategy)

Short Position: Being obligated to deliver a commodity or instrument, as opposed to owning the commodity or instrument, for example, having fewer resources than load (see "Long Position").

Short Term Market: Short-term firm purchases and sales covering longer periods than next day to next week transactions that are handled in the spot market (see Spot Market).

Short-run Mean Reverting Variations: These are variables that deviate and revert to the mean in the short-run. Within the two-factor lognormal model described in Appendix G there is a short-run component and a long-run component. Only the short-run component incorporates a statistically estimated mean reversion parameter that the model utilizes in determining a stochastic variable's value. Stochastic variables will exhibit mean reversion in the short-run when the mean reversion parameter is non-zero.

Skew: A characteristic of a probability distribution which is not symmetric. For example a positively skewed distribution (with respect to PVRR) is characterized by many smaller than expected outcomes and a few extremely higher than expected outcomes. When distributions are positively skewed, the mean is observed to be higher than the median.

Simple-Cycle Combustion Turbine (SCCT): A combustion turbine, fueled with fossil fuel (natural gas) used for the generation of electricity without the recovery of waste heat.

Spot Market: As conventionally defined, the spot market refers to day-ahead and real-time purchases and sales of electricity. The IRP defines spot market more broadly to include market purchases and sales outside of existing long-term contracts, and pursuant to PacifiCorp's system simulation model dispatch logic.

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities.

Standard Market Design (SMD): Proposed FERC Legislation, NOPR RM1-12-000, July 2002 suggests that all load serving entities must meet minimum capacity reserve planning margin of 12% or face potential penalties.

Standard Deviation: A measure of dispersion in a distribution, the square root of the arithmetic average of the squares of the deviations.

Static Var Compensator (SVC): A power line device used for voltage support. It is used to automatically supply or absorb reactive power to maintain a pre-set voltage level.

Stochastic Data Input Tools: Refers to statistical analysis tools used to estimate input parameters for MARKETSYM stochastic simulations.

Stochastic Modeling: The representation of stochastic ("random") processes using statistical methods to predict outcomes, such as short-term price trends (see Deterministic modeling).

Stochastic Risk: For purposes of the IRP, Stochastic risks include those risks which can be numerically represented and whose variability can be reasonably represented by a known statistical process. Stochastic risks are typically associated with business as usual variability in underlying parameters, such as variations in power price.

Swap: an exchange of cash flows between a seller and the buyer. The seller owns capacity and energy at a fixed price and has exposure if market prices move lower.

System Benefit Charge (SBC): A charge included in utility rates to be used for the benefit of utility customers for certain programs, such as encouraging renewable resources or energy efficiency. In Oregon, these are collected by investor-owned utilities, and administered by the Energy Trust of Oregon.

Tolling Option: This is an arrangement whereby a party moves fuel to a power generator and receives kilowatt-hours in return for a pre-established fee.

Transition Benefit: The positive difference between a resource's value, whether determined by administrative valuation or by the sales price in an auction, and the sum of that resource's net book value and FASB 109 asset and inventory balance, minus any Pre-ERTA ITC divided by (1-tax rate). Also referred to as a "stranded benefit" or "stranded cost".

U.S. DOE: The Federal Department of Energy, which administers Federal energy policies and programs.

Value at Risk (VAR): The worst portfolio loss that can be reasonably expected to happen over a specified horizon under normal market conditions, at a specified confidence level (such as 95% or 99%).

Variance: The square of the standard deviation.

Vertical Market Segments (VMS): Building types or commercial activities defined based on standard industrial classification.

WACC: Weighted average cost of capital. The after-tax WACC of 7.2% was utilized as the discount rate throughout the IRP in calculating present value of revenue requirements (PVRRs).

WECC: Western Electricity Coordinating Council (formerly known as the Western Systems Coordinating Council, or WSCC); an organization that works with its members to assess and enforce compliance with established criteria and policies for ensuring the reliability of the region's electric service.

Western Regional Air Partnership (WRAP): A multi-stakeholder process led by states, industry, federal land managers, Native American tribes and environmental groups to improve air quality in the west.

Wheeling: Transmission of electricity by a transmission provider that does not own or directly use the power it is transmitting. Wholesale wheeling refers to bulk transactions conducted in the wholesale power markets.

Wholesale Sales: Energy supplied to other utilities, municipals, Federal and State electric agencies, and power marketers for resale ultimately to end-use customers.