PACIFIC POWER
A DIVISION OF PACIFICORP

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May 30, 2007

VIA ELECTRONIC FILING AND
OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capital Street NE, Ste. 215
Salem, OR 97301-2551

Attn: Vikie Bailey-Goggins
Administrator - Regulatory Operations

RE: Commission Order No. 07-002, Integrated Resource Planning Guideline; Compliance Filing – Commitment 30, Docket No. UM-1209

Dear Ms. Bailey-Goggins:

Enclosed are an original and five (5) copies and a compact disk of PacifiCorp's 2007 Integrated Resource Plan (IRP). Copies of the report and appendices are available electronically and will be posted on PacifiCorp's website, at www.pacificorp.com.

This IRP is submitted to the Oregon Public Utility Commission (the "Commission") pursuant to the new Integrated Resource Planning guidelines issued in Docket No. UM-1056, Order No. 07-002. Appendix I contains a table that outlines how PacifiCorp addressed each of the procedural and substantive elements of the Commission's rules (see Table I.3 in the "IRP Regulatory Compliance" section). PacifiCorp respectfully requests that the Commission acknowledge the IRP in its entirety in accordance with its rules and fully support the IRP conclusions, including the proposed action plan.

Additionally, PacifiCorp submits the IRP filing to meet the MidAmerican Energy Holdings Company ("MEHC") and PacifiCorp transaction commitment that was adopted by Commission Order No. 06-082 in Docket UM-1209. Specifically, Commitment 30 provides that:

> 30) PacifiCorp will continue to produce Integrated Resource Plans according to the then current schedule and the then current Commission rules and orders.

The IRP also addresses other MEHC and PacifiCorp transaction commitments related to renewable resources, transmission and advanced coal technologies in Chapter 2, Table 2.4 of the IRP report.

As the Commission is aware, the purpose of PacifiCorp's IRP is to: (1) determine future long term resource needs and develop an informed and comprehensive assessment of the cost and risk implications of alternatives for meeting those needs, and (2) develop a framework of future actions to ensure PacifiCorp continues to provide reliable, least-cost service with manageable and reasonable risk to its customers. PacifiCorp expects its obligations to provide electricity to its customers to continue to grow. Moreover, rapidly evolving state resource policies aimed at reducing the carbon footprint of utilities and expanding renewable energy use will increase system planning complexity and cost uncertainty. PacifiCorp's IRP and associated action plan recognize these important challenges.

It is respectfully requested that all formal correspondence and Staff requests regarding this filing be address to the following:

By e-mail (preferred):	datarequest@pacificorp.com
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If there are informal inquiries concerning the filing, or if someone in your agency/organization did not receive a copy of the filing and would like to have one, please contact Pete Warnken, Manager Integrated Resource Planning at (503) 813-5518 or Joelle Steward, Regulatory Manager, at (503) 813-5542.

PacifiCorp appreciates all the time and effort Oregon participants have dedicated to helping in the development of the IRP.

Sincerely,

Andrea L. Kelly
Vice President, Regulation

Cc: Service List UM-1209 (w/out enclosures)

CERTIFICATE OF SERVICE

I hereby certify that on this 30th day of May, 2007, I caused to be served, via E-mail, if address available or U.S. Mail a true and correct copy of the Cover Letter regarding PacifiCorp's 2007 Integrated Resource Plan (Commitment 30) in UM-1209 to the following:

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Debbie DePetris
Regulatory Analyst

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2007

Integrated Resource Plan

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

This 2007 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP 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 IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Left to Right):
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Hydroelectric Generation: Yale Reservoir (Washington)
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1. EXECUTIVE SUMMARY

INTRODUCTION

PacifiCorp's 2007 Integrated Resource Plan (IRP) presents a framework of future actions to ensure PacifiCorp continues to provide reliable, least-cost service with manageable and reasonable risk to its customers. Active public involvement from customer interest groups, regulatory staff, regulators and other stakeholders provided considerable guidance in the development of this IRP. The analytical approach used conforms to all State Standards and Guidelines, and resulted in a preferred portfolio that represents a balance of resource additions that meet future customer needs while minimizing cost, balancing diverse stakeholder interests and addressing environmental concerns. This IRP builds on PacifiCorp's prior resource planning efforts and reflects significant advancements in portfolio modeling and risk analysis.

PLANNING PRINCIPLES AND OBJECTIVES

The mandate for an IRP is to assure, on a long-term basis, an adequate and reliable electricity supply at the lowest reasonable cost and in a manner "consistent with the long-run public interest." The main role of the IRP is to serve as a roadmap for determining and implementing the company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and MidAmerican Energy Holdings Company (MEHC) transaction commitments that related to IRP activities.

As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

The emphasis of the IRP is to determine the most robust resource plan under a reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future. The modeling is intended to support rather than overshadow the expert judgment of PacifiCorp's decision-makers. The preferred portfolio is not meant to be a static planning product, but rather is expected to evolve as part of the ongoing planning process. As a multi-objective planning effort, the IRP must reach a balanced position upon considering several priorities and accounting for diverse and sometimes conflicting stakeholder views. In short, the IRP cannot be all things to all people. As the owner of the IRP, PacifiCorp is uniquely positioned to determine the resource plan that best accomplishes IRP objectives on a system-wide basis, thereby meeting customer, community, and investor obligations collectively.

THE PLANNING ENVIRONMENT

There are many significant external influences that impact PacifiCorp's long-term resource planning, as well as recent procurement activities driven by the company's past IRPs. External influences are comprised of events and trends in the power industry marketplace, along with government policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

One major issue within the power industry marketplace is capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). The pace of new generation additions has begun to slow again in the west, raising the question of future resource adequacy in certain areas. The Western Electricity Coordinating Council 2006 Power Supply Assessment indicates that the Rocky Mountain sub-region will show a resource deficit by 2010.

Another significant issue is the prospect for long-term natural gas commodity price escalation and continued high volatility. Following an unprecedented increase in natural gas commodity escalation and volatility, forecasters expect a medium-term, temporary drop in natural gas commodity prices due to liquefied natural gas (LNG) facility expansion. Price uncertainty will continue because greater LNG imports will strengthen the linkage to volatile global gas and energy markets.

One of the largest issues emerging from governmental policy and regulatory initiatives is how to plan given an eventual, but highly uncertain, climate change regulatory regime. Not only have there been significant policy developments for currently-regulated pollutants, but there have also been important state-level climate change regulatory initiatives. Other regulatory issues include state renewable portfolio standards, hydropower relicensing, and major relevant provisions of the Energy Policy Act of 2005.

In conjunction with resource planning efforts, PacifiCorp has a greenhouse gas mitigation strategy that includes a public working group to consider emission reduction best practices, carbon dioxide scenario analysis for the IRP and procurement programs, renewable generation and demand-side management resource acquisition plans, and emissions accounting.

Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak load obligations are met on a reliable basis. Various regional transmission planning processes in the Western Interconnection have developed over the last several years to serve as the primary forums where major transmission projects are developed and coordinated. PacifiCorp is engaged in a number of these planning initiatives.

The Energy Policy Act of 2005, the first major energy law enacted in more than a decade, includes numerous provisions impacting electric utilities. Key provisions include (1) the promotion of clean coal technology, renewable energy, and nuclear power, (2) the encouragement of more hydroelectric production through streamlined relicensing procedures and increased efficiency, (3) the use of time-based metering options, and (4) the provision of mandatory reliability standards.

PacifiCorp's recent resource procurement activities include requests for proposal for east-side base load resources and renewable resources. In addition, requests for proposals have been issued for demand-side resource programs.

PacifiCorp's planning process is further impacted by the rapid evolution of state-specific resource policies that place, or are expected to place, constraints on PacifiCorp's resource selection decisions, and disparate state interests that complicate the company's ability to address state IRP requirements to the satisfaction of all stakeholders.

RESOURCE NEEDS ASSESSMENT

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.4 percent annually from 2007 to 2016, which is slightly faster than the average annual historical growth rate (See Table 1.1). The eastern portion of the PacifiCorp system continues to grow faster than the western system, with an average annual energy growth rate of 3.2 percent and 0.8 percent, respectively, over the forecast horizon.

Table 1.1 – Historical and Forecasted Average Energy Growth Rates for Load

Average Annual Growth Rate	Total	OR	WA	WY	CA	UT	ID
1995-2005	**1.6%**	0.1%	1.4%	1.4%	1.3%	3.0%	1.3%
2007-2016	**2.4%**	0.6%	1.3%	5.6%	1.1%	2.7%	1.0%

On both a capacity and energy basis, load and resource balances are calculated using existing resource levels, obligations and reserve requirements. Based on load and resource balance calculations, the company projects a summer peak resource deficit for the PacifiCorp system beginning in 2008 to 2010, depending on the capacity planning reserve margin assumed. Table 1.2 shows the annual capacity position (megawatt resource surplus or deficit) for the system using a 12 percent and 15 percent planning reserve margin, while Figure 1.1 shows the corresponding annual resource and obligation levels.

Table 1.2 – Capacity System Position for 12% and 15% Planning Reserve Margin

System Position (MW)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
12% PRM	665	113	73	(791)	(1,038)	(2,446)	(2,563)	(2,794)	(2,842)	(3,171)
15% PRM	415	(147)	(188)	(1,073)	(1,327)	(2,768)	(2,890)	(3,126)	(3,176)	(3,513)

The PacifiCorp deficits prior to 2011 to 2012 will be met by additional renewables, demand-side programs, and market purchases. The company will consider other options during this time frame if they are cost-effective and provide other system benefits. This could include acceleration of a natural gas plant to complement the accelerated and expanded acquisition of renewable wind facilities. On an average annual energy basis, the system becomes deficient beginning in 2009 (Figure 1.2), based on a 12 percent planning reserve margin. To address these widening deficits in a cost-effective and risk-informed manner, a mix of resource types is anticipated.

Figure 1.1 – System Capacity Chart

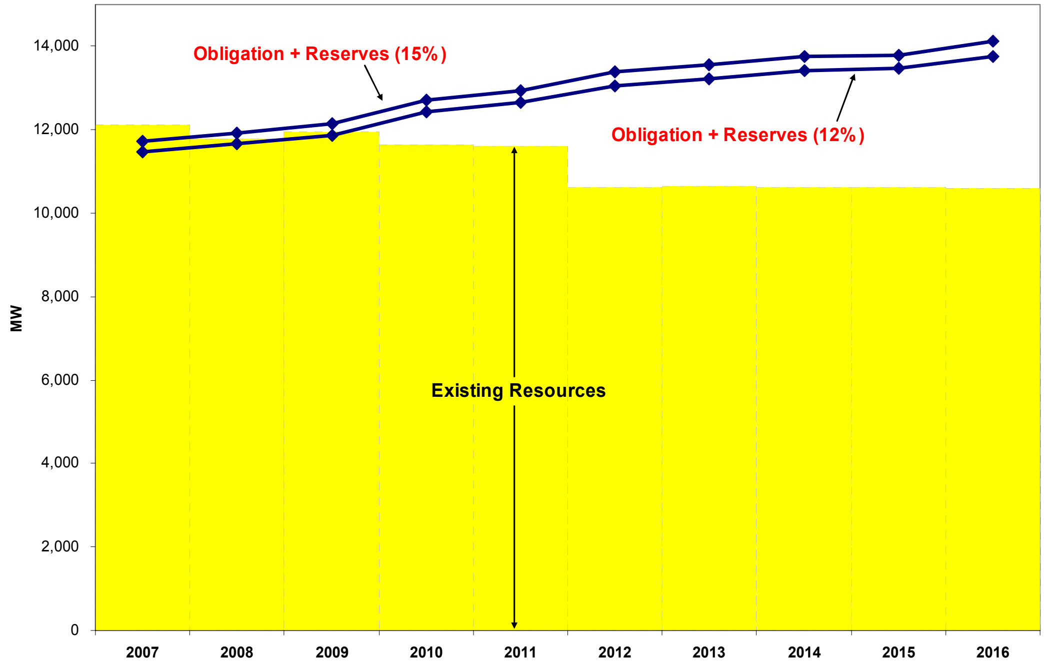
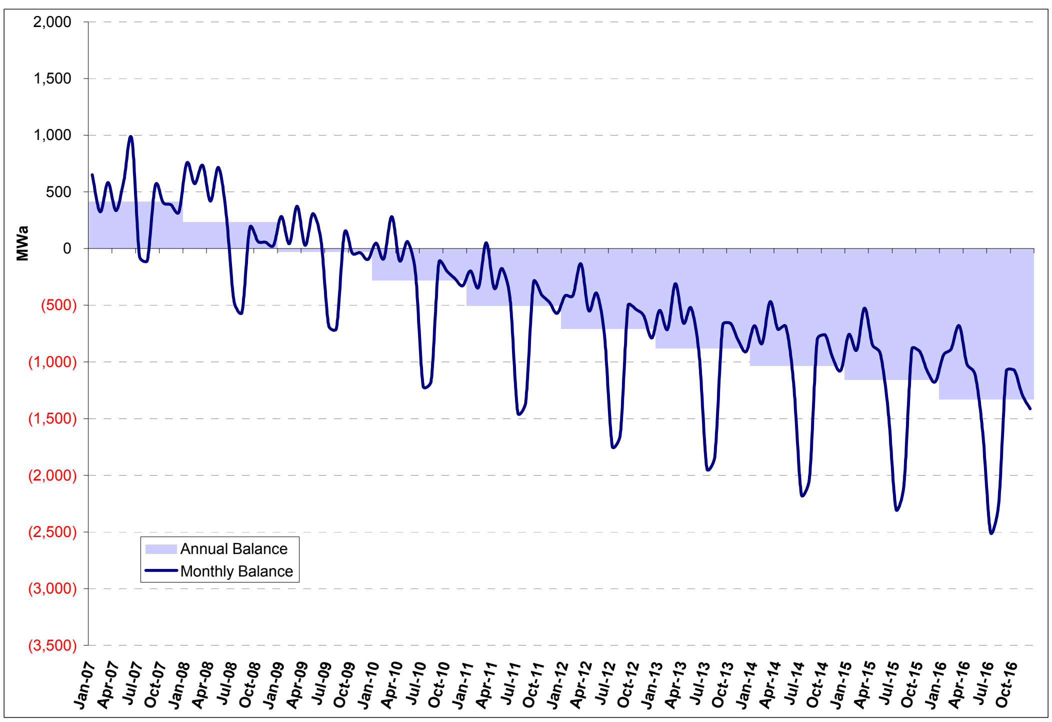


Figure 1.2 – Monthly and Annual Average Energy Balance



RESOURCE OPTIONS

The company developed cost and performance profiles for supply-side resources, demand-side management programs, transmission expansion projects, and firm market purchases (front office transactions) for use in portfolio modeling. Each supply-side option also included the estimation and use of capital cost ranges for each supply-side option. These cost ranges reflect cost uncertainty, and their use in this plan acknowledges the significant construction cost increases that are occurring.

PacifiCorp used the Electric Power Research Institute's Technical Assessment Guide (TAG®), along with recent project experience and consultant studies, to develop its supply-side resource options. The purpose of using TAG data is to rely on consistently-derived cost estimates from a well-respected independent outside source. The TAG database is considered the default source for developing the supply-side resource alternatives used in the 2007 IRP. Values are adjusted as necessary using information from PacifiCorp or other sources that reflects corporate or location-specific considerations. TAG capital costs for certain technologies were adjusted to be more in line with PacifiCorp's recent cost studies and project experience. In addition, TAG emission estimates were adjusted based on permitting expectations in PacifiCorp's service territory. The use of TAG information is new to PacifiCorp's integrated resource planning process.

The company also developed transmission resources to support meeting loads with new generation options, to integrate wind, to enhance transfer capability and maintain reliability across PacifiCorp's system, and to boost import/export capability with respect to external markets. These transmission resources were entered as options in PacifiCorp's capacity expansion optimization tool, and were thus allowed to compete directly with other resources for inclusion in portfolios.

MODELING AND RISK ANALYSIS APPROACH

The IRP modeling effort seeks to determine the comparative cost, risk, supply reliability, and emissions attributes of resource portfolios.

PacifiCorp used two modeling tools for portfolio analysis: the Capacity Expansion Module (CEM) and the Planning and Risk (PaR) Module. The CEM performs a deterministic least-cost optimization with resource options over the twenty-year study period. The CEM operates by minimizing for each year the operating costs for existing resources subject to system load balance, reliability and other constraints. Over the study period, it also optimizes resource additions subject to resource investment and capacity constraints (monthly peak loads plus a planning reserve margin for a 24-zone model topology). The PaR module is a chronological commitment/dispatch production cost model that was operated in probabilistic (stochastic) mode to develop risk-adjusted portfolio performance measures.

The 2007 IRP modeling effort consisted of resource screening, risk analysis portfolio development, and detailed production cost and stochastic risk analysis. For resource screening, the company used the CEM to evaluate generation, load control, price-responsive demand-side management, market purchases, and transmission resources on a comparable basis with the use of "alternative future" scenarios. The main purpose of these scenarios is to identify general resource patterns attributable to changes in assumptions, and to help identify robust resources—those that frequently appear in the model's optimized portfolios under a range of futures. PacifiCorp sought assistance from public stakeholders to construct the alternative future scenarios, which capture variations in potential CO_2 regulatory costs, natural gas prices, wholesale electricity prices, retail load growth, and the scope of renewable portfolio standards.

Using the results from the alternative future scenario studies, PacifiCorp defined risk analysis portfolios for stochastic simulation. The CEM was used to help build fixed resource investment schedules for wind and distributed resources, and to optimize the selection of other resource options according to specific resource strategies. Other key portfolio development criteria included diversity among the major new resource types and the impact of evolving state resource policies. The resulting portfolios were then simulated using the PaR model. The PaR simulations incorporate stochastic risk in its production cost estimates by using Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability.

PacifiCorp devoted considerable effort to model the effect of CO_2 emission compliance strategies. Stochastic simulations were conducted with various CO_2 emission cost adders to capture the risks associated with potential CO_2 emission compliance regulations. Since the probability of realizing a specific CO_2 emissions cost cannot be determined with a reasonable degree of accuracy, potential CO_2 emission costs were treated as a scenario risk in this IRP. PacifiCorp defines a scenario risk as an externally-driven fundamental and persistent change to the expected value of some parameter that is expected to significantly impact portfolio costs. This risk category is intended to embrace abrupt changes to risk factors that are not amenable to stochastic analysis. The practice of combining stochastic simulation with CO_2 cost adder scenario analysis represents advancement with respect to the modeling approach used for PacifiCorp's 2004 IRP.

All risk analysis portfolios were simulated with five CO_2 adder levels—\$0/ton, \$8/ton, \$15/ton, \$38/ton, and \$61/ton (in 2008 dollars)—and associated forward gas/electricity price forecasts. The company modeled both a cap-and-trade and emissions tax compliance strategy, and expanded its reporting of CO_2 emissions impacts.

Portfolio performance was assessed with the following measures: (1) stochastic mean cost (Present Value of Revenue Requirements), (2) customer rate impact, measured as the levelized net present value of the change in the system average customer price due to new resources for 2007 through 2026, (3) emissions externality cost, (4) capital cost, (5) risk exposure, (6) CO_2 and other emissions, (7) and supply reliability statistics.

The preferred portfolio is selected from among the risk analysis portfolios primarily on the basis of relative cost-effectiveness, customer rate impact, and cost/risk balance across the CO_2 adder levels. The preferred portfolio represents the most robust resource plan under a reasonably wide range of potential futures.

MODELING AND PORTFOLIO SELECTION RESULTS

PacifiCorp assessed "alternative future" scenarios to determine resources and capacity quantities suitable for inclusion in risk analysis portfolios. Based on the Capacity Expansion Module's optimized investment plans, the company selected wind (as a proxy for all renewable resources), combined heat and power, supercritical pulverized coal, combined cycle combustion turbine, single-cycle combustion turbine, integrated gasification combined cycle (IGCC), load control programs, transmission additions and short-term market purchases in subsequent portfolio studies.

The company studied portfolios using its stochastic production cost simulation model. These portfolios were distinguished by a variety of resource strategies intended to address major portfolio risks, such as carbon regulations and natural gas/electricity price volatility. These resource strategies were distinguished by the planning reserve margin level and the quantity and timing of wind, pulverized coal, front office transactions, and IGCC resources included.

The portfolio analysis yielded the following general conclusions:

- Diversification of resources helps to balance costs and risks. A combination of supercritical pulverized coal, additional renewable generation, and gas-fired resources is desired to achieve a low-cost portfolio that effectively addresses all major sources of risk; conversely, portfolios dominated by a single resource type were found to be more expensive and risky for customers. Studies also demonstrated that increasing wind capacity and reducing reliance on market purchases promotes a better balance of portfolio cost and risk.
- Eliminating front office transactions after 2011 decreased risk exposure and increased portfolio cost. To maintain planning flexibility and resource diversity, PacifiCorp will continue to rely on them as needed to support energy requirements in the west control area, and use them as needed to address peak load requirements in the east control area.
- While the portfolio analysis indicated that lowering the planning reserve margin increased portfolio stochastic risk and reduced reliability, the decision on what margin to adopt is a subjective one that depends on balancing portfolio risk against affordability. The portfolio modeling also showed that reducing the planning reserve margin from 15% to 12% increased CO_2 and other emissions due to greater reliance on the company's existing coal fleet.

Based on superior performance with respect to stochastic cost, customer rate impact, cost-versus-risk balance, and supply reliability, a portfolio with the following characteristics was chosen as the preferred portfolio:

- A total of 2,000 megawatts of renewable resources by 2013
- An additional 100 megawatts of load control (Class 1 demand-side management) beginning in 2010
- A west-side combined cycle combustion turbine in 2011
- High-capacity-factor resources in the east in 2012 and 2014
- East-side combined cycle combustion turbines in 2012 and 2016
- Balance of system need fulfilled by front office transactions beginning in 2010
- Transmission additions between 2010 and 2014 to support integration of the resource portfolio with loads

The preferred portfolio's specific proxy resources and acquisition timing are shown in Table 1.3.

Table 1.3 – PacifiCorp's 2007 IRP Preferred Portfolio

Supply and Demand-side Proxy Resources			Nameplate Capacity, MW									
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combined cycle CT	2x1 F class with duct firing						548				
	Combined cycle CT	1x1 G class with duct firing										357
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	393	272	97	3	149	192	165
West	CCCT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Load control, Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	-	219	64	555	657	247	246	249
	Annual Additions, Long Term Resources		300	300	100	312	839	1,125	318	527	-	357
	Annual Additions, Short Term Resources		-	-	-	612	336	652	660	396	438	414
	Total Annual Additions		300	300	100	924	1,175	1,777	978	923	438	771

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

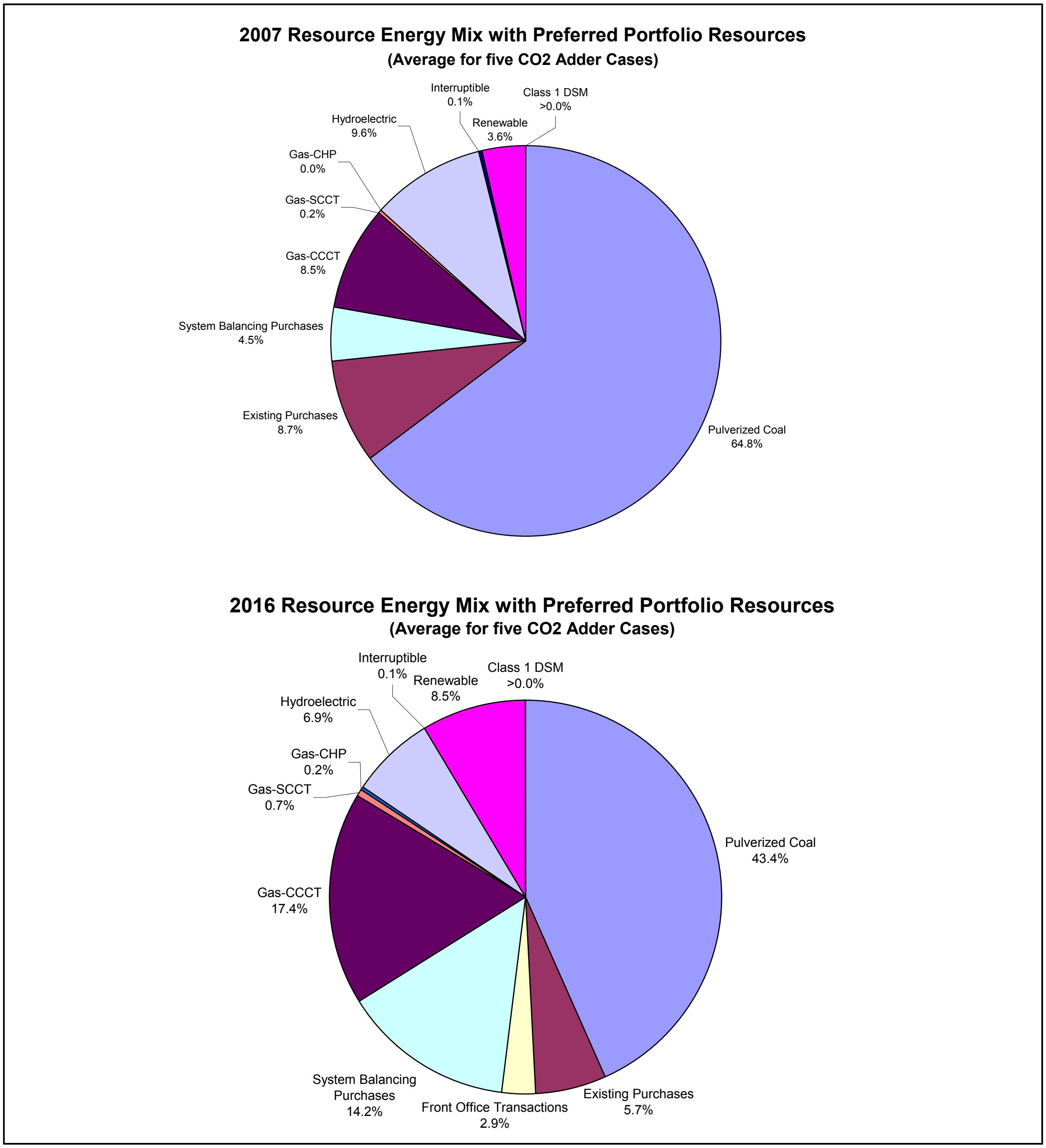
Transmission Proxy Resources*		Transfer Capability, Megawatts									
	Resource	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Path C Upgrade: Borah to Path-C South to Utah North				300						
	Utah - Desert Southwest (Includes Mona - Oquirrh)						600				
	Mona - Utah North						400				
	Craig-Hayden to Park City						176				
	Miners - Jim Bridger - Terminal						600				
	Jim Bridger - Terminal								500		
West	Walla Walla - Yakima				400						
	West Main - Walla Walla					630					
	Total Annual Additions	-	-	-	700	630	1,776	-	500	-	-

* Transmission resource proxies represent a range of possible procurement strategies, including new wheeling contracts or construction of transmission facilities by PacifiCorp or as a joint project with other parties.

The preferred portfolio reflects a diverse resource mix, as evidenced by the increasing contribution of renewables, gas-fired, and front office transactions to system generation. Figure 1.3 compares the system energy mixes for 2007 and 2016, which include preferred portfolio resources and reflect the average generation across the five CO_2 cost adders modeled.

While the preferred portfolio is based on a target planning reserve margin of 12 percent, PacifiCorp is targeting a reserve margin range of 12 to 15 percent to increase planning flexibility given a time of rapid public policy evolution and wide uncertainty over the resulting down-stream cost impacts. The preferred portfolio also is consistent with the company's strategic view on the role of firm market purchases for meeting capacity needs: that limited use of such purchases is beneficial by increasing planning flexibility and portfolio diversity, but that the company seeks less reliance on them for the long term. Market availability to support the level of firm purchases in the preferred portfolio is adequate as evidenced by recent purchase offer activity. For example, requests in 2007 for third-quarter projects for 2007-2012 yielded over 5,000 megawatts in offers.

Figure 1.3 – Projected PacifiCorp Resource Energy Mix



ACTION PLAN

The integrated resource plan is intended to provide guidance for the company's resource procurement activities over the next few years. To follow through on the findings of this resource plan, PacifiCorp's action plan includes:

- **Reaffirming commitments to renewable resources:**
  - Accelerate its previous commitment to acquire 1,400 megawatts of cost-effective renewable resources from 2015 to 2010,
  - Increase the amount of cost-effective renewable resources to 2,000 megawatts by 2013,
  - Actively seek to add transmission infrastructure to deliver wind power to key load areas. Investigate adding flexible generating resources, such as natural gas, to integrate new wind resources
  - Enhance its integrated resource planning modeling to address renewable portfolio standards and the impacts of adding large quantities of wind resources to its system
- **Increased focus on energy efficiency:**
  - Continue to run programs to acquire 250 average megawatts of cost-effective energy efficiency, and
  - Add an additional 200 average megawatts of cost-effective energy efficiency initiatives
- **Maintaining and expanding load control programs:**
  - Maintain and build upon the existing 150 megawatts of irrigation and air conditioning load control in Utah and Idaho,
  - Add 100 megawatts of additional load control split between East and West beginning in 2010,
  - Leverage voluntary demand-side measures, such as demand buyback, to improve system reliability during peak load hours, and
  - Incorporate the results of the demand-side management potentials study into the company's demand-side management programs and future integrated resource plans.
- **Studying and addressing environmental issues:**
  - Enhance its integrated resource planning modeling to address new carbon regulations, and
  - Take a leadership role in discussions on global climate change and continue to investigate carbon reduction technologies, including nuclear power.
- **Addressing transmission constraints:**
  - Expand its transmission system to allow the resources identified in the preferred portfolio to serve customer loads in a cost-effective and reliable manner
- **Adding a diverse mix of base load / intermediate load resources:**
  - Acquire up to 1,700 megawatts of base load / intermediate load resources on the east side of its system for the term 2012 through 2014, through a mix of thermal resources and purchases, consistent with the April 2007 filed request for proposal, and,
  - Acquire 200 to 1,350 megawatts of base load / intermediate load resources on the west side of its system from 2010 to 2014 through a mix of thermal resources and purchases.

2. IRP COMPONENTS, PLANNING PRINCIPLES, OBJECTIVES, AND APPROACH

Chapter Highlights

- PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."
- As a multi-objective planning effort, the IRP must reach a balanced position upon considering several priorities and accounting for diverse and sometimes conflicting stakeholder views.
- The IRP is a roadmap for PacifiCorp's long-term resource strategy, developed according to seven planning principles. One of the principles is that it strategically aligns with business priorities and meets MEHC transaction commitments.
- Key analytical and modeling objectives were to (1) evaluate all resources on a comparable basis using the company's new resource expansion optimization tool, and (2) enhance uncertainty and risk analysis.
- The outcome of PacifiCorp's portfolio analysis is a preferred portfolio that represents the lowest-cost diversified resource plan that accounts for cost/risk trade-offs, system reliability, ratepayer impacts, and CO_2 emissions. The preferred portfolio is also the most robust resource plan under a reasonably wide range of potential futures.
- PacifiCorp continuously seeks to improve the IRP public process; a number of recent initiatives to enhance stakeholder engagement for this IRP are profiled.
- PacifiCorp summarizes the progress towards meeting 18 MEHC transaction commitments that related to IRP activities.

INTRODUCTION

This chapter outlines the components of this Integrated Resource Plan (IRP), and describes the groundwork for its development: the set of planning principles and analysis objectives that underpin the IRP development effort, and the overall approach for building it.

This IRP builds on PacifiCorp's prior resource planning efforts and reflects significant advancements in portfolio modeling and risk analysis. It was developed in a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties. PacifiCorp is filing this IRP with its state regulatory agencies, and requests that they acknowledge and support its conclusions, including the Action Plan.

2007 INTEGRATED RESOURCE PLAN COMPONENTS

The basic components of PacifiCorp's 2007 IRP, and where they are addressed in this report, are outlined below.

- The set of IRP principles and objectives that the company adopted for this IRP effort, as well as a discussion on customer/investor risk allocation (this chapter)
- An assessment of the planning environment, including market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3)
- A resource needs assessment covering the company's load forecast, status of existing resources, resource expansion alternatives, and determination of the load and energy positions for the 10-year resource acquisition period (Chapter 4)
- Profiles and background information for the resource options considered for addressing future capacity deficits (Chapter 5)
- A description of the IRP modeling and risk analysis approach (Chapter 6)
- A summary of modeling results and PacifiCorp's preferred portfolio (Chapter 7)
- An action plan linking the company's preferred portfolio with specific implementation actions (Chapter 8)

The IRP appendices, included as a separate volume, comprise base modeling assumptions, supporting technical information, detailed Capacity Expansion Module (CEM) modeling results, supplementary portfolio information, studies intended to meet certain state commission IRP acknowledgement requirements, and status reports on IRP regulatory compliance and action plan progress. PacifiCorp's response to written comments on the draft IRP report is incorporated in Appendix F.

THE ROLE OF PACIFICORP'S INTEGRATED RESOURCE PLANNING

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[1] The main role of the IRP is to serve as a roadmap for determining and implementing the company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, risk, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment

[1] The Oregon and Utah Commissions cite "long run public interest" as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Utah Commission cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decisionmaking process.

tradeoffs. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

Given this role and the long-term planning focus, it is important to note the qualifications associated with the IRP so that the planning outcome can be placed in the proper context. First, resource portfolio analysis seeks to help clarify the unknown future as opposed to predicting it. Consequently, the emphasis of the IRP is to determine the most robust resource plan under a reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future. In tandem with the robustness concept is the view that selection of the preferred portfolio should not be overly influenced by any particular set of quantitative results given the complexity and inherent imprecision of the modeling effort. In other words, modeling is intended to support and not overshadow the expert judgment of PacifiCorp's decision-makers.

A second IRP qualification is that the preferred portfolio is not meant to be a static planning product, but rather is expected to evolve as part of the ongoing planning process. As resources are acquired and new planning information comes in, the company refreshes the preferred portfolio and action plan based on the set of planning principles enumerated below. Because the IRP is a road mapping effort, it is not intended as a referendum on specific resource decisions. The preferred portfolio represents a snapshot view of PacifiCorp's long-term resource planning strategy informed by current information. As emphasized in this IRP and prior ones, specific resource acquisition decisions stem from PacifiCorp's competitive procurement process.

A third qualification is that as a multi-objective planning effort, the IRP must reach a balanced position upon considering several priorities and accounting for diverse and sometimes conflicting stakeholder views. In short, the IRP cannot be all things to all people. As the owner of the IRP, PacifiCorp is uniquely positioned to determine the resource plan that best accomplishes IRP objectives on a system-wide basis, thereby meeting customer and investor obligations collectively.

PLANNING PRINCIPLES

PacifiCorp subscribed to a number of planning principles that guided the overall IRP development effort and resource decision-making process.

- Development of the IRP is guided by the state commission rules and guidelines for integrated resource planning, as well as specific IRP process and analysis requirements arising from state commission acknowledgement proceedings. At the same time, the company conducted its IRP process with the understanding that commission IRP rules and acknowledgement proceedings are not intended to usurp its decision-making authority for resource acquisition.

- PacifiCorp continues to plan on a system-wide basis. However, newly enacted state energy and environment policy mandates (and those under consideration) present considerable challenges for planning on this basis. This IRP considers such state mandates as part of the portfolio development and analysis process, acknowledging that the definition of an "optimal" portfolio must be extended to accommodate sometimes disparate state policy goals.

- With portfolio costs increasing due to rapid construction price increases and the move towards more expensive alternative technologies to meet new state resource acquisition policies, PacifiCorp is more mindful of rate impact considerations for this IRP.

- The IRP and associated action plan was developed with PacifiCorp and MidAmerican Energy Holding Company (MEHC) business principles in mind, and meets MEHC transaction commitments. The business principles that relate to long-term resource planning include (1) improving electricity system reliability, (2) investing in physical assets that bolster corporate strength and competitiveness, and (3) protecting the environment in a cost-effective manner.

- The company subscribes to a portfolio management approach for acquiring resources to meet its future load obligations. It seeks a diversified, low-cost mix of resources that minimizes price and environmental risk for its customers while enhancing value for its investors.

- PacifiCorp continues to plan using the proxy resource approach, whereby resource options included in the IRP models are constituted with generic cost and performance attributes and assume PacifiCorp ownership for supply-side alternatives to simplify the analysis. (Some adjustments are made to resource attributes to reflect corporate experience or location-specific considerations, such as elevation for gas-fired resources.) With this proxy approach, modeled resources are only indicative of the resources that might be procured, the specific attributes of which may be modified to account for conditions at procurement time. Wind was selected as the proxy resource for all renewables based on wide availability in PacifiCorp's service territory, relative cost-effectiveness and cost certainty, and technological maturity. In the case of modeled transmission options, these are proxies representing a range of procurement strategies, including new wheeling contracts or construction of transmission facilities by PacifiCorp or as joint projects with other parties.

- PacifiCorp believes that CO_2 regulation will come into play during the 10-year resource acquisition period that is the focus of this IRP (2007 through 2016). Potential carbon dioxide emission costs serve as a major source of portfolio risk that is addressed through scenario analysis and balancing this risk against others. PacifiCorp also believes that given the state of knowledge concerning prospective CO_2 regulations, it is prudent to not assign probabilities to specific CO_2 cost outcomes as part of portfolio risk analysis.

- The company continues to seek improvements in the stakeholder engagement process and enhance the level of transparency of the overall process.

KEY ANALYTICAL AND MODELING OBJECTIVES

The main analytical objective of the IRP is to determine the preferred resource portfolio for the next ten years (2007-2016) based on a finding of need and a comparative assessment of available resource opportunities. The preferred portfolio represents the resource plan that has the best balance of cost and risk.

A key analytical objective for this IRP was to treat all resource options on a comparable basis when developing alternative portfolios. To that end, PacifiCorp added a resource expansion optimization tool (the Capacity Expansion Module, or CEM) into its portfolio modeling framework. This model performs automated economic screening of resources and determines the optimal resource expansion plan based on planning scenarios. This tool enabled thermal generation, renewable generation, market purchases, demand-side management, and transmission to compete against each other on the basis of their impact on Present Value of Revenue Requirements (PVRR), the key measure of a portfolio's performance.

Important caveats associated with the CEM are that it does not capture stochastic risks in its optimization algorithm, and that it is designed as a high-level screening tool. In contrast to the Planning and Risk Module (PaR)—PacifiCorp's detailed production costing and market simulation model, the CEM cannot incorporate stochastic variables in its solution algorithm and is instead meant to address high-level system operational details. (For example, unlike the PaR, it does not capture hourly chronological commitment constraints). Consequently, a modeling objective for this IRP was to exploit the complementary but different capabilities of the CEM and PaR. Chapter 6 describes the roles that each of these models played throughout PacifiCorp's resource portfolio analysis.

An additional analytical and modeling objective for this IRP was to enhance uncertainty and risk analysis. PacifiCorp accomplished this objective by making the following data and modeling methodology changes, which are detailed later in this report.

- Incorporated stochastic simulation of candidate portfolios at various CO_2 adder levels, in contrast to running deterministic simulations with CO_2 adder levels independently as was done for the 2004 IRP.

- Introduced stochastic analysis of front office transactions (market purchases), which includes comparing stochastic risk measures of a portfolio with front office transaction resources against a portfolio in which these resources are replaced with an asset-based coal plant.

- Development of low and high capital cost estimates for supply-side resources in recognition of increased construction cost volatility trends.

- Extensive expansion of the number of input sensitivity studies relative to the 2004 IRP, including 36 studies using the CEM and 27 stochastic studies using PaR.

- Incorporated probability-weighted forward gas price curves into the IRP models; the curves are based on a weighted average of PIRA Energy's low, medium, and high gas price cases.

A final analytical objective for this IRP was to determine an appropriate level of reliance on market purchases given their flexibility benefits and risks. As opposed to the 2004 IRP, where market purchases were treated as a fixed resource, for this IRP they were handled as a competing resource option with associated prices modeled as stochastic variables to capture price risk.

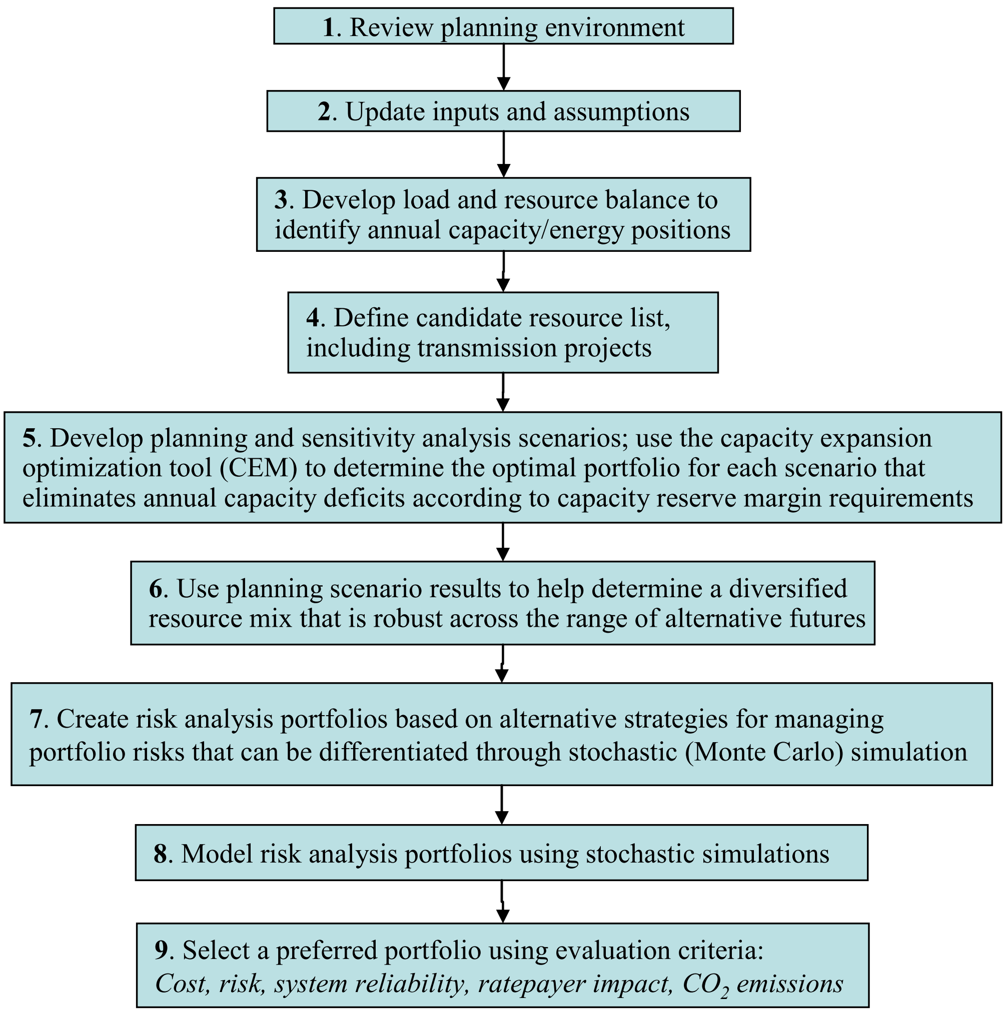
INTEGRATED RESOURCE PLANNING APPROACH OVERVIEW

The 2007 IRP approach consisted of both analytical and public processes that occurred in tandem. These two processes are described below.

Analytical Process

The analytical process is comprised of nine major steps that are summarized in Figure 2.1. Chapter 3 addresses Step 1, "review the planning environment". Step 2, "update inputs and assumptions", is covered largely in Appendices A and J. Chapter 4 covers Step 3, "develop load and resource balance". Step 4, "define candidate resource list" is treated in Chapter 5. Steps 5 through 8, which address the modeling and risk analysis process and results, are covered in Chapters 6 and 7.

Figure 2.1 – Integrated Resource Planning Analytical Process Steps



As shown in the diagram, the outcome of the analytical process is a preferred portfolio that represents the lowest-cost diversified resource plan that accounts for cost, risk, system reliability, ratepayer impacts, and CO_2 emissions.

Public Process

The core of the 2007 IRP public process was a series of 13 public meetings designed to facilitate information sharing, collaboration, and expectations setting for the IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed.

PacifiCorp held three of the meetings in 2005—two load forecasting workshops (August 3 and October 5) and a 2007 IRP kick-off meeting on December 7. Table 2.1 shows the timeline of the public meetings in relation to the overall IRP timeline, commencing with the December 7 IRP kick-off meeting. Appendix F, in the separate appendix volume, provides more details concerning the public meeting process and individual meetings. Stakeholder engagement efforts are chronicled in the last section of this chapter.

Table 2.1 – IRP and Public Process Timeline

	IRP Timeline	Aug-05	Sept-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06
		Prepare IRP Assumptions and Models										
		Public Meetings										
1	Technical Workshop - Load Forecasting, August 3, 2005	X										
2	Technical Workshop - Load Forecasting, October 5, 2005			X								
3	General Public Input Meeting, December 7, 2006					X						
4	Technical Workshop - Renewables, Jan 13, 2006						X					
5	Technical Workshop - Load Forecasting, Jan. 24, 2006						X					
6	Technical Workshop - DSM, Feb 10, 2006							X				
7	General Public Meeting, April 20, 2006									X		
8	General Public Meeting, May 10, 2006										X	
9	General Public Meeting, June 7, 2006											X
10	General Public Meeting, August 23, 2006											
11	General Public Meeting, October 31, 2006											
12	General Public Meeting, February 1, 2007											
13	General Public Meeting, April 18, 2007											

	IRP Timeline	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07
		Conduct Analysis / Prepare IRP Report										File
1	Technical Workshop - Load Forecasting, August 3, 2005											
2	Technical Workshop - Load Forecasting, October 5, 2005											
3	General Public Input Meeting, December 7, 2006											
4	Technical Workshop - Renewables, Jan 13, 2006											
5	Technical Workshop - Load Forecasting, Jan. 24, 2006											
6	Technical Workshop - DSM, Feb 10, 2006											
7	General Public Meeting, April 20, 2006											
8	General Public Meeting, May 10, 2006											
9	General Public Meeting, June 7, 2006											
10	General Public Meeting, August 23, 2006		X									
11	General Public Meeting, October 31, 2006				X							
12	General Public Meeting, February 1, 2007								X			
13	General Public Meeting, April 18, 2007										X	X

In addition to the public meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and consultation throughout the IRP process. The company maintains a website (http://www.pacificorp.com/Navigation/Navigation23807.html), e-mail "mailbox" (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support stakeholder communications and address inquiries by public participants.

PacifiCorp and its parent company, MidAmerican Energy Holdings Company (MEHC), also participated in numerous organizations and working groups that address regional planning issues in the areas of supply, system coordination, energy management, and transmission resources. Table 2.2 lists a number of these organizations by focus area.

Table 2.2 – Participation in Regional Planning Organizations and Working Groups

Organization	Focus Area
Western Electricity Coordinating Council/Seams Steering Group – Western Interconnection (SSG-WI)	System reliability and adequacy
Northwest Power Pool	System reliability and adequacy
Northwest Power and Conservation Council	Regional power system
Pacific Northwest Utilities Conference Committee (PNUCC)	Regional power system
Northwest Wind Integration Technical Workgroup	Wind
Big Sky Carbon Sequestration Partnership Energy Future Coalition	Climate change
Global Climate Change Working Group (MEHC commitment)	Climate change
Integrated Gasification Combined Cycle Working Group (MEHC commitment)	Clean coal technology
Northwest Energy Efficiency Alliance	Energy efficiency
Conservation Advisory Council (Energy Trust of Oregon)	Energy efficiency
Utah DSM Advisory Group	Energy efficiency
Washington DSM Advisory Group	Energy efficiency
Northwest Transmission Assessment Committee (NTAC)	Transmission
Rocky Mountain Area Transmission Study (RMATS)	Transmission
Northern Tier Transmission Group (NTTG)	Transmission
Western Regional Transmission Expansion Partnership	Transmission
Ely Energy Center / Robinson Summit – Harry Allen 500 kV Transmission Project Regional Planning Review Group	Transmission
Utah Resource Forum	Peak power demand issues

Finally, PacifiCorp provided IRP participants the opportunity to critique the draft IRP document in April 2007.

STAKEHOLDER ENGAGEMENT

PacifiCorp maintains a strong commitment to improve the value of the IRP public process to external stakeholders as well as the company. This is evidenced by a number of initiatives taken by PacifiCorp during 2005 and 2006. First, PacifiCorp instituted a stakeholder satisfaction survey in the spring of 2005. The purpose of this survey was to determine if the company was on the right track with respect to execution of the IRP public process, and to solicit recommendations on improvements to better support stakeholder needs.[2] PacifiCorp implemented several recommendations for the 2007 IRP, as detailed in Table 2.3.

[2] A presentation summarizing the survey results can be found on PacifiCorp's Web site. The link to the presentation is http://www.pacificorp.com/File/File52811.pdf.

Table 2.3 – Public Process Recommendations Implemented for the 2007 IRP

Public Process Recommendation	Outcome
Distribute model run results during the course of the IRP modeling phase rather than waiting to distribute them at the public meetings.	PacifiCorp distributed via e-mail a document package to participants on October 4, 2006 with updated CEM modeling results and other documentation, including an updated paper that describes the planning scenarios and associated input assumptions. The company also distributed a paper on candidate portfolio development on October 12, 2006 and February 5, 2007.
Distribute appendices for review along with the main draft IRP document.	PacifiCorp distributed for review the draft appendices to support the review of the main document.
Work to ensure that the participant base is more evenly balanced as far as representation is concerned; issue personal invitations to stakeholders as necessary.	PacifiCorp expanded its meeting invitation and contact list from about 80 individuals for the 2004 IRP to 135 for the 2007 IRP. PacifiCorp also added a video-conference site in Cheyenne, Wyoming, to facilitate meeting attendance. This list expansion also encompasses IRP meeting invitations to MEHC transaction stakeholders per Commitment #48, described in the next section.
Send information out earlier to prepare for meetings.	PacifiCorp maintains a policy of distributing meeting handouts at least two days in advance of a meeting. Exceptions may occur due to the need for last-minute management reviews of meeting materials. Only one of the 13 public meetings was impacted in this way.

Another PacifiCorp initiative was to front-load public meetings during the 2007 IRP schedule and to focus those meetings on the more contentious, technical, or complex issues. This meeting plan was prompted by the company's concern during the 2004 IRP process that critical stakeholder input was provided well after the point where recommendations and concerns could be easily addressed in the process. Based on the outcome of these meetings, the company found the front-loading approach beneficial as an early sounding board for its proposed modeling assumptions and approaches, and intends to build on this approach for the next IRP.

MIDAMERICAN ENERGY HOLDINGS COMPANY IRP COMMITMENTS

MEHC and PacifiCorp committed to continue to produce IRPs according to the schedule and Commission rules and orders at the time the transaction was in process. Other commitments were made to (1) encourage stakeholders to participate in the integrated resource planning process and consider transmission upgrades, (2) develop a plan to achieve renewable resource commitments, (3) consider utilization of advanced coal-fuel technology such as IGCC technology when adding coal-fueled generation, (4) conduct a market potential study of additional demand-side management and energy efficiency opportunities, (5) evaluate expansion of the Blundell Geothermal resource, and (6) include utility "own/operate" resources as a benchmark in future request for proposals. A detailed description of these commitments and a description of how they are addressed in the 2007 Integrated Resource Plan are provided in Table 2.4 below.

Table 2.4 – MidAmerican/PacifiCorp Transaction Commitments Addressed in the IRP

MEHC Commitment Number	MEHC Commitment Description	How the Commitment is Addressed in the 2007 IRP
30	PacifiCorp will continue to produce Integrated Resource Plans according to the then-current schedule and the then-current Commission rules and orders.	This plan complies with various Commission rules and orders.
48	IRP Stakeholder Process: PacifiCorp will provide public notice and an invitation to encourage stakeholders to participate in the Integrated Resource Plan (IRP) process. The IRP process will be used to consider Commitments 34, 39, 40, 41, 44, 52 and 53. PacifiCorp will hold IRP meetings at locations or by using communications technologies that encourage broad participation.	Public notice for each Integrated Resource Planning meeting was provided to stakeholders. For all Integrated Resource Planning meetings, video conference facilities were made available in Portland, Oregon and Salt Lake City, Utah in addition to a telephone link. Several of the meetings also included video conference facilities in Cheyenne, Wyoming. Consideration of commitments 34, 39, 40, 41, 44, 52 and 53 are described below.
34	Transmission Investment: MEHC and PacifiCorp have identified incremental transmission projects that enhance reliability, facilitate the receipt of renewable resources, or enable further system optimization. Subject to permitting and the availability of materials, equipment and rights-of-way, MEHC and PacifiCorp commit to use their best efforts to achieve the following transmission system infrastructure improvements: • Path C Upgrade (~\$78 million) – Increase Path C capacity by 300 MW (from S.E. Idaho to Northern Utah). The target completion date for this project is 2010. • Mona - Oquirrh (~\$196 million) – Increase the import capability from Mona into the Wasatch Front (from Wasatch Front South to Wasatch Front North). This project would enhance the ability to import power from new resources delivered at or to Mona, and to import from Southern California by "wheeling" over the Adelanto DC tie. The target completion date for this project is 2011. • Walla Walla - Yakima or Mid-C (~\$88 million) – Establish a link between the "Walla Walla bubble" and the "Yakima bubble"	Each of these three transmission upgrades has been included in the company's modeling. The Path C upgrade is included as a planned transmission upgrade while the other two projects are options that can be selected by the Capacity Expansion Module.

MEHC Commitment Number	MEHC Commitment Description	How the Commitment is Addressed in the 2007 IRP
	and/or reinforce the link between the "Walla Walla bubble" and the Mid-Columbia (at Vantage). Either of these projects presents opportunities to enhance PacifiCorp's ability to accept the output from wind generators and balance the system cost effectively in a regional environment. The target completion date for this project is 2010. (Footnote): It is possible that upon further review, a particular investment might not be cost-effective, optimal for customers or able to be completed by the target date. If that should occur, MEHC pledges to propose an alternative to the Commission with a comparable benefit.	
39	In Commitment 31, MEHC and PacifiCorp adopt a commitment to source future PacifiCorp generation resources consistent with the then-current rules and regulations of each state. In addition to that commitment, for the next ten years, MEHC and PacifiCorp commit that they will submit as part of any commission approved RFPs for resources with a dependable life greater than 10 years and greater than 100 MW—including renewable energy RFPs—a 100 MW or more utility "own/operate" alternative for the particular resource. It is not the intent or objective that such alternatives be favored over other options. Rather, the option for PacifiCorp to own and operate the resource which is the subject of the RFP will enable comparison and evaluation of that option against other viable alternatives. In addition to providing regulators and interested parties with an additional viable option for assessment, it can be expected that this commitment will enhance PacifiCorp's ability to increase the proportion of cost-effective renewable energy in its generation portfolio, based upon the actual experience of MEC and the "Renewable Energy" commitment offered below.	This commitment is being addressed in the company's request for proposals.
40	MEHC reaffirms PacifiCorp's commitment to acquire 1,400 MW of new cost-effective renewable resources, representing approximately 7% of PacifiCorp's load. MEHC and PacifiCorp commit to work with developers and bidders to bring at least 100 MW of cost-effective wind resources in service within one year of the close of the transaction.	This Integrated Resource Plan reflects the commitment to acquire 1,400 megawatts of new cost-effective renewable resources. The 100 megawatt goal has been met, and the company is within 54 megawatts of reaching the 400 megawatt goal at the time of this

MEHC Commitment Number	MEHC Commitment Description	How the Commitment is Addressed in the 2007 IRP
	MEHC and PacifiCorp expect that the commitment to build the Walla-Walla and Path C transmission lines will facilitate up to 400 MW of renewable resource projects with an expected in-service date of 2010. MEHC and PacifiCorp commit to actively work with developers to identify other transmission improvements that can facilitate the delivery of cost-effective wind energy in PacifiCorp's service area. In addition, MEHC and PacifiCorp commit to work constructively with states to implement renewable energy action plans so as to enable PacifiCorp to achieve at least 1,400 MW of cost-effective renewable energy resources by 2015. Such renewable energy resources are not limited to wind energy resources.	report. The company has included several transmission upgrades in 2007 Integrated Resource Planning analyses that can facilitate additional renewable resource development. A Renewables Action Plan to achieve at least 1,400 megawatts of cost-effective renewable energy resource by 2015 was filed concurrently with the 2007 IRP.
41	MEHC supports and affirms PacifiCorp's commitment to consider utilization of advanced coal-fuel technology such as super-critical or IGCC technology when adding coal-fueled generation.	IGCC technology is included as a resource option in the 2007 Integrated Resource Planning process. Chapter 5 details various clean coal project activities, including the joint Wyoming Infrastructure Authority/PacifiCorp IGCC project.
44	MEHC and PacifiCorp commit to conducting a company-defined third-party market potential study of additional DSM and energy efficiency opportunities within PacifiCorp's service areas. The objective of the study will be to identify opportunities not yet identified by the company and, if and where possible, to recommend programs or actions to pursue those opportunities found to be cost-effective. The study will focus on opportunities for deliverable DSM and energy efficiency resources rather than technical potentials that may not be attainable through DSM and energy efficiency efforts. On-site solar and combined heat and power programs may be considered in the study. During the three-month period following the close of the transaction, MEHC and PacifiCorp will consult with DSM advisory groups and other interested parties to define the proper scope of the study. The findings of the study will be reported back to DSM advisory groups, commission staffs, and other interested stakeholders and will be used by the Company in helping to direct ongoing DSM	The demand side management potential study is underway and is expected to be completed on schedule. The results of the study will be used to inform future Integrated Resource Plans.

MEHC Commitment Number	MEHC Commitment Description	How the Commitment is Addressed in the 2007 IRP
	and energy efficiency efforts. The study will be completed within fifteen months after the closing on the transaction, and MEHC shareholders will absorb the first $1 million of the costs of the study. PacifiCorp further commits to meeting its portion of the NWPPC's energy efficiency targets for Oregon, Washington and Idaho, as long as the targets can be achieved in a manner deemed cost-effective by the affected states. In addition, MEHC and PacifiCorp commit that PacifiCorp and MEC will annually collaborate to identify any incremental programs that might be cost-effective for PacifiCorp customers. The Commission will be notified of any additional cost-effective programs that are identified.	
52	Upon closing, MEHC and PacifiCorp commit to immediately evaluate increasing the generation capacity of the Blundell geothermal facility by the amount determined to be cost-effective. Such evaluation shall be summarized in a report and filed with the Commission concurrent with the filing of PacifiCorp's next IRP. This incremental amount is expected to be at least 11 MW and may be as much as 100 MW. All cost effective increases in Blundell capacity, completed before January 1, 2015, should be counted toward satisfaction of PacifiCorp's 1,400 MW renewable energy goal, in an amount equal to the capacity of geothermal energy actually added at the plant.	A report describing the Blundell evaluation was filed in March 2007 with all six states.
53	MEHC or PacifiCorp commit to commence as soon as practical after close of the transaction a system impact study to examine the feasibility of constructing transmission facilities from the Jim Bridger generating facilities to Miners Substation in Wyoming. Upon receipt of the results of the system impact study, MEHC or PacifiCorp will review and discuss with stakeholders the desirability and economic feasibility of performing a subsequent facilities study for the Bridger to Miners transmission project.	This commitment was completed by the company on August 23, 2006. The Miners substation to Jim Bridger transmission upgrade is included as an option in the 2007 Integrated Resource Planning analysis.

MEHC Commitment Number	MEHC Commitment Description	How the Commitment is Addressed in the 2007 IRP
C22a, O26a, Wy21a	Concurrent with its next IRP filing, PacifiCorp commits to file a ten-year plan for achieving the 1,400 MW renewables target, including specific milestones over the ten years when resources will be added. The filing will include a ten-year plan for installing transmission that will facilitate the delivery of renewable energy and the achievement of its 2015 goal of at least 1,400 MW of cost-effective renewable energy. Within six (6) months after the close of the transaction, MEHC and PacifiCorp will file with the Commission a preliminary plan for achieving the 1,400 MW renewable target.	The preliminary plan was filed on September 21, 2006. The final plan was filed concurrently with the 2007 IRP filing.
C22b, O26b, Wy21b	PacifiCorp commits to address as part of its next IRP the appropriate role of incremental hydropower projects in meeting the 1400 MW renewables target.	A Renewables Action Plan to achieve at least 1,400 megawatts of cost-effective renewable energy resources by 2015 was concurrently with the 2007 IRP. It will address hydropower projects in the document.
I23, U17, Wy20	PacifiCorp agrees to include the following items in the 2006 IRP [2007 IRP]: a) a wind penetration study to reappraise wind integration costs and cost-effective renewable energy levels; and b) an assessment of transmission options for PacifiCorp's system identified in the RMATS scenario 1 related to facilitating additional generation at Jim Bridger and, on equal footing, new cost-effective wind resources.	a) Wind supply curves were developed and used to select wind on a comparable basis with other resources in the Capacity Expansion Module. Appendix J addresses the company's wind resource methodology used in this plan. b) The company included transmission options in southwest and southeast Wyoming as potential upgrades in its modeling in order to facilitate wind development in Wyoming.

TREATMENT OF CUSTOMER AND INVESTOR RISKS

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders[3]." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

[3] Since PacifiCorp is now a subsidiary of a privately-owned company, this section will refer to PacifiCorp's "investors" as opposed to "shareholders."

Stochastic Risks

One of the principle sources of risk that is addressed in this IRP is stochastic risk. Stochastic risks are quantifiable uncertainties for particular variables. The variables addressed in this IRP include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

PacifiCorp uses proxy resources in its portfolio evaluation and determination of the preferred portfolio. These proxy resources are characterized with generic capital cost estimates that are adjusted to reflect recent project experience and company-specific financial parameters. The actual cost of a generating or transmission asset is expected to vary from the cost assumed in this plan. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risks

Scenario risks pertain to abrupt or fundamental changes to model inputs that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risk facing PacifiCorp are government actions to regulate CO_2 emissions. This scenario risk relates to the uncertainty in predicting the scope, timing, and cost impact of CO_2 emission compliance rules.

At the present time, the issue of how the risk associated with uncertain CO_2 regulatory costs should be allocated to customers and investors is an open one. Complicating factors include the following:

- The prospect that a supercritical coal plant that is part of the company’s preferred portfolio could receive IRP acknowledgement in one state and not another.
- The need to weigh resource CO_2 cost risk against the opportunity costs of investing in alternative resources with their own attendant cost risks (In this IRP, PacifiCorp shows that coal plants provide important portfolio risk diversification benefits when paired with other low-CO_2 emitting resources.)
- Ratepayer/investor risk allocation may be treated differently among PacifiCorp’s jurisdictions depending on state resource policies and the evolution of inter-jurisdictional cost allocation approaches designed to address them.

At the combined Climate Change and Integrated Gasification Combined Cycle Working Group meeting on November 28, 2006, PacifiCorp facilitated a public discussion on ratepayer/investor risk allocation in the event that the company acquires a coal unit that is not able to capture and store CO_2 emissions.[4] The outcome of the discussion was that no consensus could be reached on the risk allocation issue and how the company can effectively proceed with resource planning given the regulatory uncertainties; more questions were raised than answers provided.

4 PacifiCorp arranged this discussion on CO_2 regulatory risk in fulfillment of an MEHC transaction commitment.

3. THE PLANNING ENVIRONMENT

Chapter Highlights

- The pace of new generation additions has begun to slow again in the west, raising the question of future resource adequacy in certain areas. The Western Electricity Coordinating Council 2006 Power Supply Assessment indicates that the Rockies sub-region will show a resource deficit by 2010.
- Following an unprecedented increase in natural gas commodity escalation and volatility, forecasters expect a medium-term, temporary drop in natural gas commodity prices due to liquefied natural gas (LNG) facility expansion. Price uncertainty will continue because greater LNG imports will strengthen the linkage to volatile global gas and energy markets.
- In conjunction with resource planning efforts, PacifiCorp has a greenhouse gas mitigation strategy that includes a public working group to consider emission reduction best practices, carbon dioxide scenario analysis for the IRP and procurement programs, renewables and demand-side management resource acquisition plans, and emissions accounting.
- Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak load obligations are met on a reliable basis. Various regional transmission planning processes in the Western Interconnection have developed over the last several years to serve as the primary forums where major transmission projects are developed and coordinated. PacifiCorp is engaged in a number of these planning initiatives.
- The Energy Policy Act of 2005, the first major energy law enacted in more than a decade, includes numerous provisions impacting electric utilities. Key provisions include the promotion of clean coal technology and renewable energy, the encouragement of more hydroelectric production through streamlined relicensing procedures and increased efficiency, the use of time-based metering options and the provision of mandatory reliability standards.
- PacifiCorp's recent resource procurement activities include requests for proposal for east-side baseload resources and renewable resources. In addition, requests for proposals have been issued for demand-side resource programs.
- PacifiCorp's planning process is impacted by (1) rapid evolution of state-specific resource policies that place, or are expected to place, constraints on PacifiCorp's resource selection decisions, and (2) disparate state interests that complicate the company's ability to address state IRP requirements to the satisfaction of all stakeholders.

INTRODUCTION

This chapter profiles the major external influences that impact PacifiCorp's long-term resource planning as well as recent procurement activities driven by the company's past IRPs. External influences are comprised of events and trends in the power industry marketplace, along with government policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Concerning the power industry marketplace, the major issues addressed include capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC) and the prospects for long-term natural gas commodity price escalation and continued high volatility. As discussed elsewhere in the IRP, future natural gas prices and the role of gas-fired generation and market purchases are some of the critical factors impacting the determination of the preferred portfolio that best balances low-cost and low-risk planning objectives.

On the government policy and regulatory front, the largest emerging issue facing PacifiCorp is how to plan given an eventual, but highly uncertain, climate change regulatory regime. While this chapter reviews the significant policy developments for currently-regulated pollutants, it focuses on climate change regulatory initiatives, particularly at the state level. A high-level summary of the company's greenhouse gas emissions mitigation strategy follows. Other regulatory topics covered include state renewable portfolio standards, hydropower relicensing, and major relevant provisions of the Energy Policy Act of 2005; namely, those pertaining to clean coal technologies, renewable energy, demand response programs and advanced metering, fossil fuel generation efficiency standards, and transmission reliability.

MARKETPLACE AND FUNDAMENTALS

PacifiCorp's system does not operate in an isolated vacuum. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity marketplace of the Western Interconnection. These transactions yield economic efficiency by assuring that resources with the lowest operating cost are serving demand in a region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp has historically participated in the wholesale marketplace in this fashion, making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on terms and time scales ranging from hourly to years in advance. Without it, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supplies that would go unutilized in all but unusual circumstances and would substantially diminish its capability to efficiently match delivery patterns to the profile of customer demand. The market is not without its risks, as the experiences of the 2000-2001 market crisis and several more recent but briefer periods of price escalation in the west have underscored. Marketplace risks have been amplified in recent years by the growing role of natural gas fired generation in the Western Interconnection that have tied electricity market prices increasingly to natural gas commodity prices.

Electricity Markets

Two overriding issues will tend to influence western electricity markets over the term of this plan's decision horizon. One of those is the evolution of natural gas prices, which is discussed in the next section. The other is the overall balance of generating resources in the Western Interconnection in relation to demand.

A slow pace of generating resource additions during the 1990s and robust growth in demand across the West were the main ingredients that set up the market crises of 2000-2001, although there were many other well documented contributing factors. Since that crisis, a wave of new capacity additions and demand side actions have righted the resource imbalance and restored aggregate planning and operating reserve margins. However, the pace of new generation additions has begun to slow again, raising the question of future resource adequacy and associated marketplace turmoil.

The WECC currently reports adequate reserve margins for the Western Interconnection in aggregate, based on existing resources. Currently, the Western Interconnection maintains an adequate margin of generation over projected demand through 2011 with the existing resource base and new generation projects currently under construction or in advanced development. However, Southern California, the desert southwest and the Rocky Mountain sub-regions show narrower projected margins and are more vulnerable to resource shortfalls or unexpected demand growth spurts, with the potential to propagate market upsets. Indeed, widespread and extremely hot temperatures in summer 2006 tested resource adequacy and caused a period of elevated market prices and a few instances of supply inadequacy near misses.

The pace and location of future resource additions have the potential to balance supply and demand adequately, but could also significantly undershoot or overshoot demand growth. Major transmission additions could also contribute to overall supply adequacy, but these have generally lagged generation additions and demand growth in the Western Interconnection.

Underlying these issues is the unresolved question of resource adequacy and responsibility throughout the Western Interconnection. The WECC does not have a regional planning reserve requirement. Without a system-wide binding standard for resource adequacy and responsibility with a multi-year horizon consistent with the multi-year time frame for most resource additions, there is elevated risk that the WECC or some of its sub-regions will experience demand growth in excess of supplies.

Uncertainty in magnitude of demand and uncertainty in availability of resources compound the resource adequacy issue. Resource uncertainty is especially important in the Northwest, where hydro accounts for more than half of installed capacity and the average energy availability from hydro can vary substantially from year to year.

The current WECC 2006 Power Supply Assessment analyzes resource adequacy for a number of possible future conditions for sub-regions of the Western Interconnection. Under base summer conditions, this assessment indicates that three of the WECC's sub-regions (Southern California, the desert southwest and Rockies) show resource deficits by 2010. More adverse conditions accelerate the deficits for these sub-regions to 2008. These results suggest that, even for utilities or sub-regions that maintain adequate reserve margins, there is an elevated risk of periods of exposure to high and volatile market prices, and that these risks must be carefully examined in resource plans.

Natural Gas Supply and Demand Issues

Over the last four years North American natural gas markets have demonstrated unprecedented price escalation and volatility. Spot gas prices averaged $3.34/MMBtu at the Henry Hub benchmark in 2002 but more than doubled by 2005, averaging $8.80/MMBtu.

Several factors have contributed to these market conditions and their interaction will play a major role in setting natural gas prices over the medium-term future. In particular, domestic United States production has reached a plateau, with growth from the Rocky Mountain region and from unconventional resources largely offset by declining volumes from conventional mature producing regions. The higher finding and development costs of unconventional resources have also raised the price level necessary to stimulate such marginal supply growth. On the demand side, substantial growth of gas-fired generating resources has more than offset declines in industrial demand for natural gas. This shift has reduced the amount of industrial demand that is most price-elastic and increased inelastic generation demand. Substantial oil price escalation over this same time period has also supported higher natural gas prices, lifting the price of marginally competitive gas substitutes and the value of natural gas liquids.

Combined, the above factors created a pronounced supply/demand imbalance in North American markets, raising prices sufficiently high to discourage marginal demand and to attract imports from an equally tight global market. This imbalance also made North American markets more susceptible to upset from weather and other event shocks and tied them more directly to global gas and energy markets.

Most forecasters expect a gradual restoration of better supply/demand balance to North American markets over the next five years, and this profile is reflected in New York Mercantile Exchange (NYMEX) futures prices. The primary factor contributing to the forecasted price decline is a substantial growth in liquefied natural gas imports over this period. For example, the U.S. Energy Information Administration's Annual Energy Outlook projects 2010 liquefied natural gas (LNG) imports to grow by 300% over 2005 levels.

This growth in LNG imports will be supported by rapid expansion of LNG regasification capacity that is well underway in North America, but will still take several years to reach fruition. It also requires parallel growth in capital-intensive liquefaction capacity in major producing regions, which is also underway, and sufficient LNG shipping capacity, which is currently overbuilt. North American regasification capacity is now forecasted to be more than adequate within five years, and has the potential to substantially overshoot demand for these facilities early in the next decade. On the other hand, recent delays and cost escalation in major liquefaction facilities has added some uncertainty to the forecasted downward price pressure.

The momentum behind LNG growth explains the medium-term trend of declining natural gas prices seen in both forward prices, such as natural gas futures prices on the New York Mercantile Exchange, and in forecasts of prices such as the Department of Energy's Annual Energy Outlook and other proprietary forecasts. Besides the downward price trend, the growth in reliance on LNG has other implications for North American natural gas markets. With a larger fraction of North American supply coming from LNG, a stronger linkage to global gas and energy markets is solidified. How this translates to U.S. gas price volatility is by no means clear, as the contracting structure and terms and role of LNG spot cargos in global LNG markets is evolving. Recently, delays in commercial arrangements for Alaska North Slope natural gas pipeline development have escalated the potential for LNG market share gains to indefinitely delay Alaska North Slope and Mackenzie Delta arctic frontier sources, although these are not now expected to contribute to supplies before 2015 and 2011, respectively, in any case.

Several factors besides potential LNG supply delays contribute to a wide range of price uncertainty over the next five years, including constraints on U.S. production infrastructure, linkages to oil prices, and supply and demand elasticities. PacifiCorp relies on PIRA Energy's Scenario Service, which describes and quantifies a range of forecasts, as a measure of future natural gas price uncertainty. Over time PIRA's natural gas scenarios have depicted a widening range of price uncertainty.

Given the range of uncertainty over future natural gas prices, it is prudent to recognize possible high and low gas prices as well as the most likely prices. PacifiCorp lays out such cases in Chapter 5, describing low, medium, and high scenarios for both gas and wholesale electricity prices. In addition, the IRP has adopted a probability-weighted or expected value forecast case, shown in Appendix A, which is higher than the reference or most likely forecast case, implying risk asymmetry towards the up-side.

Western regional natural gas markets are likely to remain well-connected to overall North American natural gas prices for the medium term outlook. Although Rocky Mountain region production is forecasted to be among the fastest growing in North America, major pipeline expansions to the mid-west and east are slated for the next five years and these should maintain market price correlations between Cheyenne/Opal and Henry Hub. A number of west coast LNG regasification facilities have been proposed, and one in Ensenada, Mexico, is under construction and expected to begin operation in 2008. Of the other facilities proposed for the west coast, there is relatively low probability that more than one will reach completion over the next five years. In any case, the presence of west coast LNG regasification facilities is not likely to cause large or abrupt disruptions in the relationship between western regional prices and overall North American natural gas prices.

FUTURE EMISSION COMPLIANCE ISSUES

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

Currently Regulated Emissions

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

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

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

PacifiCorp is committed to responding to environmental concerns and investing in higher levels of protection for its coal-fired plants. PacifiCorp and MEHC anticipate spending $1.2 billion over the next ten years to install necessary equipment under future emissions control scenarios to the extent that it's cost-effective. The company has started its clean air projects, such as the installation of a baghouse, flue gas desulfurization and low nitrogen-oxide burners at the Huntington 2 plant.

Climate Change

Climate change has emerged as an issue that requires attention from the energy sector, including utilities. Because of its contribution to United States and global carbon dioxide emissions, the U.S. electricity industry is expected to play a critical role in reducing greenhouse gas emissions. In addition, the electricity industry is composed of large stationary sources of emissions that are thought to be often easier and more cost-effective to control than from numerous smaller sources. PacifiCorp and parent company MidAmerican Energy Holdings Company recognize these issues and have taken voluntary actions to reduce their respective CO_2 emission rates. PacifiCorp's efforts to achieve this goal include adding zero-emitting renewable resources to its generation portfolio such as wind, landfill gas, combined heat and power (CHP) and investing in on-system and customer-based energy efficiency and conservation programs. PacifiCorp also continues to examine risk associated with future CO_2 emissions costs. The section below summarizes issues surrounding climate change policies.

Impacts and Sources

As far as sources of emissions are concerned, according to the U.S. Energy Information Administration, CO_2 emissions from the combustion of fossil fuels are proportional to fuel consumption. Among fossil fuel types, coal has the highest carbon content, natural gas the lowest, and petroleum in-between. In the Administration's *Annual Energy Outlook 2006* reference case, the shares of these fuels change slightly from 2004 to 2030, with more coal and less petroleum and natural gas. The combined share of carbon-neutral renewable and nuclear energy is stable from 2004 to 2030 at 14 percent. As a result, CO_2 emissions increase by a moderate average of 1.2 percent per year over the period – 5,900 million metric tons in 2004 to 8,114 million metric tons by 2030, slightly higher than the average annual increase in total energy use. At the same time, the economy becomes less carbon intensive: the percentage increase in CO_2 emissions is one-third the increase in GDP, and emissions per capita increase by only 11 percent over the 26-year period.

According to the Administration's *Annual Energy Outlook 2006* report, the factors that influence growth in CO_2 emissions are the same as those that drive increases in energy demand. Among the most significant are population growth; increased penetration of computers, electronics, appliances, and office equipment; increases in commercial floor space; growth in industrial output; increases in highway, rail, and air travel; and continued reliance on coal and natural gas for electric power generation. The increases in demand for energy services are partially offset by efficiency improvements and shifts toward less energy-intensive industries. New CO_2 mitigation programs, more rapid improvements in technology, or more rapid adoption of voluntary programs could result in lower CO_2 emissions levels than projected here.

PacifiCorp carefully tracks CO_2 emissions from operations and reports them in its annual emissions filing with the California Climate Action Registry.

International and Federal Policies

Numerous policy activities have taken place and continue to develop. At the global level, most of the world's leading greenhouse gas (GHG) emitters, including the European Union (EU), Japan, China, and Canada, have ratified the Kyoto Protocol. The Protocol sets an absolute cap on GHG emissions from industrialized nations from 2008 to 2012 at 7% below 1990 levels. The Protocol calls for both on-system and off-system emissions reductions. While the U.S. has thus far rejected the Kyoto Protocol, numerous proposals to reduce greenhouse gas emissions have been offered at the federal level. The proposals differ in their stringency and choice of policy tools. The Bush Administration has proposed an 18% voluntary carbon intensity reduction target, i.e., emissions per unit of economic output. Such an approach could translate into a tons/MWh approach in the electricity sector.

Democratic victories on November 7, 2006 in the House and Senate appear likely to boost efforts to strengthen U.S. global warming policy, but it is far from certain whether the 110th Congress and President Bush will work together over the coming two years to enact a first-ever federal law to cap greenhouse gas emissions.

With Democrats taking over the House and the Senate in January, experts and lawmakers alike expect an emboldened legislative branch to advance an entirely new of set environment and energy proposals unlike anything seen during President Bush's previous six years in the White House. The Senate Environment and Public Works Committee, chaired by Senator Barbara Boxer (D-CA), has committed to having a set of intensive hearings on the issue of global warming during 2007.

On January 5, 2007, Senator Bingaman (D-NM) circulated a discussion draft which identifies his current proposal for mandatory greenhouse gas reduction legislation. On January 12, 2007, Senators Lieberman (I-CT) and McCain (R-AZ) reintroduced their proposed federal carbon legislation.[5] Senate legislation has also been released by Senators Sanders (I-VT) and Boxer (D-CA)[6] and Senators Feinstein (D-CA) and Carper (R-DE).[7]

On January 18, 2007, House Speaker Pelosi (D-CA) announced the formation of a new Select Committee on Energy Independence and Global Warming. The panel will draw on members from as many as nine existing panels that already have authority over the issue. Rep. Ed Markey (D-Mass.) is expected to lead the new committee, which will only be commissioned for the 110th Congress. The speaker also expressed her intent to have legislation through the committees by July 4, 2007.

Regional Initiatives

Western regional state initiatives were significant in 2006. The most notable developments have been the Western Public Utility Commissions' Joint Action Framework on Climate Change and the Western Regional Climate Action Initiative.

On December 1, 2006, California utility regulators and their counterparts in New Mexico, Oregon and Washington pledged to coordinate efforts to limit greenhouse gas emissions. The regulators in those four states will work together to address climate change, from promoting energy efficiency to encouraging the use of clean energy. The respective heads of the California Public Utilities Commission, the Washington Utilities and Transportation Commission, the Oregon Public Utility Commission, and the New Mexico Regulation Commission signed the agreement. The Joint Action Framework on Climate Change outlines a commitment to regional cooperation to address climate change.

On February 26, 2007, during the annual winter meeting of the National Governors Association, Governors Arnold Schwarzenegger (California), Janet Napolitano (Arizona), Bill Richardson (New Mexico), Ted Kulongoski (Oregon) and Christine Gregoire (Washington) signed the Western Regional Climate Action Initiative[8] that directs their respective states to develop a regional target for reducing greenhouse gases by August 2007. By August 2008, they are expected to de-

[5] S.280, the "Climate Stewardship and Innovation Act of 2007"
[6] S.309, the "Global Warming Pollution Reduction Act"
[7] S.319, the "Electric Utility Cap and Trade Act of 2007"
[8] See, http://gov.ca.gov/mp3/press/022607_WesternClimateAgreementFinal.pdf

vise a market-based program, such as a load-based cap-and-trade program to reach the target. The five states also have agreed to participate in a multi-state registry to track and manage greenhouse gas emissions in their region. The Initiative builds on existing greenhouse gas reduction efforts in the individual states as well as two existing regional efforts. In 2003, California, Oregon and Washington created the West Coast Global Warming Initiative, and in 2006, Arizona and New Mexico launched the Southwest Climate Change Initiative.

In response to limited federal activity, state policy has grown in prominence. While some states have adopted policies that address power plant emissions directly by either capping emissions or setting an emissions rate limit (such as the Northeastern Regional Greenhouse Gas Initiative), other states have sought to reduce carbon emissions through resource selection either by adopting renewable portfolio standards or requiring utilities to consider potential carbon costs within their integrated resource planning. Within PacifiCorp's service territory, only California has adopted specific legislation directly regulating utility greenhouse gas emissions. Washington and Oregon are expected to consider and possibly adopt climate legislation modeled after the California legislation during the 2007 legislative session. Wyoming has its Carbon Committee and Utah's Governor recently convened a climate council to discuss the state climate policies. California's greenhouse gas emissions policies are profiled below.

State Initiatives

California Emissions Performance Standard (SB1368)

California Senate Bill 1368 (SB 1368), signed into law on September 29, 2006, is an emissions performance standard law designed to effectuate a rulemaking at the California Public Utilities Commission, Docket No. R.06-04-009[9], and grants authority to the California Energy Commission to promulgate a similar emissions performance standard for publicly-owned utilities. PacifiCorp has been an active participant within the Commission docket. SB 1368 establishes a greenhouse gas emissions performance standard that prohibits any load serving entity, including electrical corporations, community choice aggregators, electric service providers, and local publicly owned electric utilities, from entering into a long-term financial commitment unless base load generation complies with a greenhouse gases emission performance standard not exceed the rate of emissions of a combined-cycle natural gas facility.

A long-term financial commitment is defined as a new ownership investment in base load generation or a new or renewed contract with a term of five or more years, which includes procurement of base load generation. Base load generation includes electricity generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent.

SB 1368 precludes the California Public Utilities Commission and the California Energy Commission from approving the construction of or contract for base load generation that does not meet the greenhouse gas emissions performance standard. Costs incurred for electricity purchase agreements that are approved by the Public Utilities Commission that comply with the greenhouse gas emission performance standard are recognized as procurement costs incurred pursuant

[9] The California PUC final Emissions Performance Standard Staff Workshop Report, which includes the latest staff straw proposal, is posted on the PUC website at: www.cpuc.ca.gov/static/energy/electric/climate+change. The direct link to the Report is www.cpuc.ca.gov/published/REPORT/60350.htm.

to an approved procurement plan and the Public Utilities Commission is required to ensure timely cost recovery of those costs. Long-term financial commitments entered into through a contract approved by the Public Utilities Commission for electricity generated by a zero- or low-carbon generating resource[10] that is contracted for on behalf of consumers in California on a cost-of-service basis is recoverable in rates, and the Public Utilities Commission may, after hearing, approve an increase from one-half to one percent in the return on investment by the third party entering into the contract with an electrical corporation relating to its investment in zero- or low-carbon generation resources.

On January 25, 2007, the California Public Utilities Commission approved the decision of President Peevey and Administrative Law Judge Gottstein in Rulemaking 06-06-009[11], "Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies". The decision adopts an emissions performance standard of 1,100 pounds per megawatt-hour for new long-term base load (60%) financial commitments. The term "long-term financial commitments", will also include new financial investments by utilities in their own existing base load generation that extends the life of a plant by five years or more.

The Commission also adopted an interpretation of §§ 8341(d)(2) and (5) and clarified that it will determine compliance with the standard based on the reasonably projected net emissions over the life of a facility, but in calculating the net emissions rate, the Commission will not count carbon dioxide that is sequestered through injection in geological formations. This allows for a sequestration project to become operational after the power plant comes on line or the load serving entity enters into the contract. PacifiCorp had argued for such an interpretation as a means of allowing advanced coal projects to demonstrate compliance with the greenhouse gas emissions performance standard even though their carbon sequestering equipment may not be operational during the first few years of a project.

Regarding § 8341(d)(9)'s multi-jurisdictional utility qualification requirements for alternative compliance, the Commission adopted the tests proposed by PacifiCorp. In fact, the Commission went further and concluded that the information provided by PacifiCorp during the rulemaking process and the Oregon Public Utilities Commission's January 8, 2007 Order #07-002[12], which establishes a proceeding to examine carbon dioxide risk associated with resource decisions, were sufficient for the Commission to conclude that PacifiCorp meets the alternative compliance requirements. As a result, PacifiCorp is not obligated to submit an alternative compliance application and is only required to file an annual attestation advice letter affirming that it still satisfies the alternative compliance requirements by February 1 of each year, beginning in 2008.

The California Energy Commission must adopt regulations for municipal utilities consistent with the Public Utilities Commission rules by June 30, 2007.[13] Enforcement of the emission perform-

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[10] Zero- or low-carbon generating resource is defined as an electrical generating resource that will generate electricity while producing emissions of greenhouse gases at a rate substantially below the greenhouse gas emission performance standards, as determined by the PUC.
[11] See, http://www.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/63931.htm
[12] See, http://apps.puc.state.or.us/edockets/orders.asp?ordernumber=07-002
[13] SB1368, *supra* note 42.

ance standard begins immediately upon the establishment of the standard. Existing combined-cycle power plants that are in operation, or have a California Energy Commission final permit decision to operate as of June 30, 2007, are grandfathered under the bill and deemed to be in compliance with the greenhouse gas emission performance standard.

California Global Warming Solutions Act of 2006 (AB32)
On September 27, 2006, California Governor Arnold Schwarzenegger signed into law Assembly Bill 32 (AB 32), known as the California Global Warming Solutions Act of 2006. California has since become the focus of climate change policy due to its massive economy, the fact that it is the 12th largest emitter of greenhouse gases in the world, and has had a history of catalyzing the formation of national environmental policy and regulation.

The bill itself is fairly performance-oriented and could result in a comprehensive, and thus effective, greenhouse gas mitigation strategy beyond the traditional focus solely on utilities. Under the legislation, greenhouse gas emissions would be reduced to 1990 levels by 2020 (a 25% reduction) and further reduced to 80% below 1990 levels by 2050. In determining and measuring these levels, the protocols of the California Climate Action Registry are to be incorporated to the maximum extent feasible. AB 32 also sets forth the following milestones for the California Air Resources Board:

- **By July 1, 2007**, the Air Resources Board forms Environmental Justice and Economic & Technology Advancement advisory committees.
- **By July 1, 2007**, the Air Resources Board adopts list of discrete early action measures that can be adopted and implemented before January 1, 2010.
- **By January 1, 2008**, the Air Resources Board adopts regulations for mandatory greenhouse gas emissions reporting. The Air Resources Board defines a 1990 emissions baseline for California (including emissions from imported power) and adopts that as the 2020 statewide cap.
- **By January 1, 2009**, the Air Resources Board adopts plan indicating how emission reductions will be achieved from significant sources of greenhouse gas emissions via regulations, market mechanisms and other actions.
- **During 2009**, the Air Resources Board staff drafts rule language to implement its plan and holds a series of public workshop on each measure (including market mechanisms).
- **By January 1, 2010**, early action measures take effect.
- **During 2010**, the Air Resources Board conducts series of rulemakings, after workshops and public hearings, to adopt greenhouse gas regulations including rules governing market mechanisms.
- **By January 1, 2011,** the Air Resources Board completes major rulemakings for reducing GHGs including market mechanisms. The Air Resources Board may revise the rules and adopt new ones after January 1, 2011 in furtherance of the 2020 cap.
- **By January 1, 2012,** greenhouse gas rules and market mechanisms adopted by the Air Resources Board take effect and are legally enforceable. (Note: This deadline dovetails well with the post-2012 Kyoto Protocol negotiations.)
- **December 31, 2020,** is the deadline for achieving the 2020 greenhouse gas emissions cap enforced by the Air Resources Board.

Furthermore, prior to creating enforceable mandates or market mechanisms (i.e. cap-and-trade programs), AB 32 specifies that the Air Resources Board must evaluate at least the following factors:

- Impacts on California's economy, the environment, and public health,
- Equity between regulated entities,
- Electricity reliability,
- Conformance with other environmental laws, and
- To ensure that the rules do not disproportionately impact low-income communities.

Although AB 32 does not specify a specific market-based policy tool to address greenhouse gas emissions, Governor Schwarzenegger has steered the state regulatory agencies in the direction of an international cap-and-trade type program by issuing a new executive order related to AB 32 in October 2006. The executive order[14] specifies that:

- The California Secretary for Environmental Protection shall create a Market Advisory Committee of national and international experts to make recommendations to the State Air Resources Board on or before June 30, 2007, on the design of a market-based compliance program.
- The Air Resources Board shall collaborate with the California Secretary for Environmental Protection and the Climate Action Team to develop a comprehensive market-based compliance program with the goal of creating a program that permits trading with the European Union, the Regional Greenhouse Gas Initiative and other jurisdictions.

The executive order appears to be well in line with the text of AB 32 and cites "numerous studies" by institutions such as U.C. Berkeley, Stanford, and the Pew Center on Global Climate Change that indicate that market-based policy mechanisms, such as emissions trading, are the most efficient and effective policy tools to address climate change.

California Governor Schwarzenegger has already met with New York Governor Pataki to discuss ways that the California market mechanism for climate change can potentially tie in with the Regional Greenhouse Gas Initiative's market-based cap and trade system. Nonetheless, the extent to which these two systems can be integrated remains to be seen.

In light of the passage of AB 32, on November 1, 2006 the California Public Utilities Commission indicated via an administrative law judge's ruling that they will develop a model rule to effectuate a state-wide load-based greenhouse gas cap-and-trade program for the electricity sector. The rulemaking will be undertaken as part of the Commission's existing Docket No. R.06-04-009.[15] PacifiCorp has been an active participant within this docket.

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[14] http://gov.ca.gov/index.php?/press-release/4447/

[15] The California PUC final Emissions Performance Standard Staff Workshop Report, which includes the latest staff straw proposal, is posted on the PUC website at: www.cpuc.ca.gov/static/energy/electric/climate+change. The direct link to the Report is www.cpuc.ca.gov/published/REPORT/60350.htm.

Washington's Act Mitigating the Impacts of Climate Change 2007 (SB6001)

Washington Governor Christine Gregoire on May 3, 2007 signed Senate Bill 6001, which contains provisions aimed at reducing the state's greenhouse gas (GHG) emissions. First, the Act established the following goals for statewide GHG emissions:

- by 2020, reduce emissions to 1990 levels;
- by 2035, reduce emissions to 25 percent below 1990 levels; and
- by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below the state's expected emissions that year.

It then established en employment goal that by 2020, increase the number of clean energy sector jobs to 25,000 from the 8,400 jobs the state had in 2004.

The bill also requires by December 31, 2007, Department of Energy (DOE) and Department of Community, Trade & Economic Development (CTED) must report to the appropriate committees of the Legislature the total GHG emissions for 1990, and totals in each major sector for 1990. By December 31 of each even-numbered year beginning in 2010, DOE and CTED must report to the Governor and the Legislature the total GHG emissions for the preceding two years, and totals in each major source sector.

The Governor is also directed to develop policy recommendations on how the state can achieve the specified GHG emissions reduction goals. The recommendations must include such issues as how market mechanisms would assist in achieving the goals. The recommendations must be submitted to the Legislature during the 2008 Legislative Session.

The bill also establishes a GHG Emissions Performance Standard (EPS). Beginning July 1, 2008, the GHG emissions performance standard for all baseload electric generation for which electric utilities enter into long-term financial commitments on or after such date is the lower of:

- 1,100 pounds of GHG per megawatt-hour; or
- the average available GHG emissions output as updated by CTED.

In general, all baseload electric generation that begins operation after June 30, 2008, and is located in Washington, must comply with the performance standard. The following facilities are deemed to be in compliance with the performance standard:

- all baseload electric generation facilities in operation as of June 30, 2008, until they are the subject of long-term financial commitments;
- all electric generation facilities or power plants powered exclusively by renewable resources; and
- all cogeneration facilities in the state that are fueled by natural gas or waste gas in operation as of June 30, 2008, until they are the subject of a new ownership interest or are upgraded.

The following emissions produced by baseload electric generation do not count against the performance standard:

- emissions that are injected permanently in geological formations;

- emissions that are permanently sequestered by other means approved by DOE; and
- emissions sequestered or mitigated under a plan approved by the EFSEC, as specified in the act.

Unlike California's EPS, the Washington proposal offers some potential emissions mitigation options to allow energy from new coal plants to be used in the state. These provisions allow coal power as long as operators reduce emissions from other sources to meet the EPS. For example, a new base-load coal plant has up to five years after commencing operation to initiate a CO_2 capture-and-sequestration process to meet the law. If the technology is not available at that time, the plant owner has options to mitigate the CO_2 emissions to meet the EPS and stay in the Washington energy market. For example, a plant owner can purchase "verifiable GHG emission reductions" from another power plant located within the Western Interconnection that would not have occurred otherwise. Coal plant operators could also purchase CO_2-emitting power generators with the intent to shut them down, and use the avoided CO_2 emissions as offsets to meet the EPS for a new power plant project.

By June 30, 2008, DOE and Washington State Energy Facility Site Evaluation Council (EFSEC) must coordinate and adopt rules to implement and enforce the GHG emissions performance standard, including the evaluation of sequestration and mitigation plans. In addition, CTED must consult with specified groups, such as the Bonneville Power Administration, and consider the effects of the standard on system reliability and the overall costs to electricity customers.

In order to update the standard, CTED must conduct a survey every five years of new combined-cycle natural gas thermal electric generation turbines commercially available and offered for sale by manufacturers and purchased in the United States. CTED must use the survey results to adopt by rule the average available GHG emissions output. The survey results must be reported to the Legislature every five years, beginning June 30, 2013.

Electric utilities may not enter into long-term financial commitments for baseload electric generation unless the generation complies with the performance standard. For an investor-owned utility (IOU), the Washington Utilities and Transportation Commission (WUTC) must review a long-term financial commitment in a general rate case. The WUTC must also review an IOU's proposed decision to acquire electric generation or enter into a power purchase agreement for electricity, upon application of the utility. The process for reviewing proposed decisions must be specified in rule and conducted under the Administrative Procedures Act. The WUTC must consult with DOE when verifying compliance with the performance standard. The WUTC must adopt all implementing rules by December 31, 2008. The WUTC may exempt a utility from the performance standard for unanticipated electric system reliability needs, catastrophic events, or threat of significant financial harm arising from unforeseen circumstances.

DOE, in consultation with CTED, EFSEC, the WUTC, and the governing boards of consumer-owned utilities, must review the GHG emissions performance standard no less than every five years or upon the implementation of a federal or state law or rule regulating CO_2 emissions of electric utilities, and report to the Legislature.

By December 31, 2007, the Governor must report to the Legislature the potential benefits of creating tax incentives to encourage base load electric facilities to upgrade their equipment to reduce CO_2 emissions, the nature and level of tax incentives likely to produce the greatest benefits, and the cost of providing such incentives.

Oregon Examination of Treatment of CO_2 Policy Risk within IRP Planning

On January 8, 2007, the Oregon Public Utilities Commission issued an order within the Integrated Resource Planning docket UM 1056.[16] As part of the Order, the Commission announced it was opening an investigation to review the treatment of carbon dioxide risk in Integrated Resource Plans (per footnote 11, this will apply to future Requests for Proposals), which will ultimately replace the analysis required in Order 93-695. Next, the Commission noted in footnote five that it had committed to explore a carbon dioxide emissions performance standard for long-term power supplies in adopting the Joint Action Framework on Climate Change, and that this investigation would follow the proceeding on carbon dioxide risk in Integrated Resource Plans.

On February 8, 2007, the Oregon Public Utilities Commission announced it would begin work under docket UM-1302[17] investigating the treatment of carbon dioxide risk in Integrated Resource Plans.

Corporate Greenhouse Gas Mitigation Strategy

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

- **Policy –** PacifiCorp has established a Global Climate Change Working Group, meant to examine best utility practices for addressing carbon risk. The company has also supported legislation that enables GHG reductions while addressing core customer requirements. PacifiCorp will continue to work with regulators, legislators, and other stakeholders to identify viable tools for GHG emissions reductions.

- **Planning –** PacifiCorp has incorporated a reasonable range of values for the cost of CO_2 in the 2007 IRP in concert with numerous alternative future scenarios to reflect the risk of future regulations that can affect relative resource costs. Additional voluntary actions to mitigate greenhouse gas emissions could increase customer rates and represent key public policy decisions that the company will not undertake without prior consultation with regulators and lawmakers at state and federal levels.

- **Procurement –** PacifiCorp recognizes the potential for future CO_2 costs in requests for proposal (RFPs), consistent with its treatment in the IRP. Commercially available carbon-capturing and storage technologies at a utility scale do not exist today. Carbon-capturing technologies are under development for both pulverized coal plant designs and for coal gasification plant designs, but require research to increase their scale for electric utility use.

- **Accounting –** PacifiCorp has adopted transparent accounting of GHG emissions by joining the California Climate Action Registry. The Registry applies rigorous accounting standards,

[16] See, http://apps.puc.state.or.us/edockets/orders.asp?ordernumber=07-002

[17] See, http://apps.puc.state.or.us/edockets/docket.asp?DocketID=13896

based in part on those created by the World Business Council on Sustainable Development and the World Resources Institute, to the electric sector.

The current strategy is focused on meaningful results, including installed renewables capacity and effective demand-side management programs that directly benefit customers. While these efforts provide multiple benefits of which lower GHG emissions are a part, they are clearly attractive within an effective climate strategy and will continue to play a key role in future procurement efforts. As part of PacifiCorp's Global Climate Change Working Group effort, a Preliminary Global Climate Change Action Plan will be completed by the company in 2007 and filed with the six state utility commissions. Within the Plan, PacifiCorp expects to propose significant changes to its corporate greenhouse gas mitigation strategy.

RENEWABLE PORTFOLIO STANDARDS

A renewable portfolio standard (RPS) is a policy that obligates each retail seller of electricity to include in its resource portfolio (the resources procured by the retail seller to supply its retail customers) a certain amount of electricity from renewable energy resources, such as wind and solar energy. The retailer can satisfy this obligation by either (1) owning a renewable energy facility and producing its own power, or (2) purchasing renewable electricity from someone else's facility.

Some RPS statutes or rules allow retailers to trade their obligation as a way of easing compliance with the RPS. Under this trading approach, the retailer, rather than maintaining renewable energy in its own energy portfolio, instead purchases tradable credits that demonstrate that someone else has generated the required amount of renewable energy.

RPS policies are currently implemented at the state level[18], and vary considerably in their requirements with respect to time frame, resource eligibility, treatment of existing plants, arrangements for enforcement and penalties, and whether they allow trading of renewable energy credits.[19] As of late 2006, 23 states and the District of Columbia had adopted RPS regulations. The most recent adoption occurred in Washington, which passed a ballot measure in November 2006. Two states in PacifiCorp's service territory—California and Washington—now have an RPS in place. Recent RPS legislative and regulatory activities in California, Washington, and Oregon are summarized below.

California

In 2006, the California legislature approved, and Governor Schwarzenegger signed into law, a bill that codifies an earlier deadline for reaching the state's renewable energy goals. Existing law had established the RPS program and a goal of 20% of retail electric sales from renewable resources by 2017. The new legislation, Senate Bill 107[20], accelerates the target date to December

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[18] Interest in a federal RPS policy is expanding. For example, a bipartisan group of Senators and Representatives have re-introduced the 25x'25 House and Senate Concurrent Resolutions in January 2007 calling for a new national renewable energy supply goal of 25% by 2025.
[19] See, http://www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm
[20] SB 107 as enacted and chaptered is posted on the legislature's web site at:

31, 2010. The law now comports with earlier decisions by the California Public Utilities Commission that established the “20% by 2010” target. Senate Bill 107 requires compliance with the standard by investor-owned utilities, community choice aggregators, and electric service providers. Municipal utilities are exempt, but must meet expanded reporting requirements on their plans and accomplishments in supporting the development and use of renewable resources. Other provisions of the bill authorize the use of renewable energy credits, “flexible compliance” approaches, and program eligibility for renewable power produced outside the state if it is delivered to California locations.

Existing law requires the California Energy Commission to certify eligible renewable resources, to develop a regional accounting system to verify compliance, and to allocate and award supplemental energy payments (SEPs) to cover above-market costs of renewables. The bill requires the Energy Commission to recover all costs of the regional accounting system from user fees. The bill also requires the Energy Commission to develop tracking, accounting, verification, and enforcement mechanisms for renewable energy credits (RECs). Certain renewable resource facilities located outside the state can be eligible for SEPs, but awards to those facilities are limited to 10% of total funds available.

PacifiCorp filed a proposed compliance plan for meeting the California RPS requirements in 2006. In its filing, PacifiCorp cited its 2001 eligible[21] renewable resource generation as approximately 4% of its retail sales in California. PacifiCorp is currently required to deliver 20% of its California load from eligible renewable resources by 2010. It is also worth noting that the California legislature is currently considering legislation that would establish a 33% requirement by 2020.

Oregon

At the request of Governor Kulongoski, a number of state agencies were asked to develop a Renewable Energy Action Plan (REAP) with input from stakeholders. These agencies—Agriculture, PUC, Economic Development, Energy, Environmental Quality, Forestry and Water Resources—prepared several drafts, which were sent to interested individuals, businesses and organizations and posted on the Oregon Department of Energy Web site. Public comment and stakeholder input was taken and a series of public meetings were held before finalizing the document. The final Renewable Energy Action Plan was released in April of 2005.

The REAP contains numerous renewable energy policy goals for the state and also a mandate to "support a Renewable Energy Working Group to be coordinated through the Governor's Office and the Oregon Department of Energy to guide the implementation of this Plan." A long list of actions for state agencies is included in the Plan, as well as numerous tasks for the Renewable Energy Working Group.

A Renewable Energy Working Group was formed through a collaborative process involving the Oregon Department of Energy and the Governor's Office. The primary mission of the Renewable Energy Working Group (REWG) was to guide implementation of the Renewable Energy Action

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http://www.leginfo.ca.gov/pub/bill/sen/sb_0101-0150/sb_107_bill_20060926_chaptered.pdf

[21] The California RPS stipulated resources eligible for inclusion in meeting the RPS requirement. It should be noted that the only eligible hydro resources are those with capacity less than 30 megawatts.

Plan. Group members were tasked by the Governor to develop a legislative proposal for a RPS that would be 25 percent of retail sales by 2025. The Renewable Energy Working Group's legislative proposal was introduced during the 2007 legislative session and is currently under consideration. The proposal would establish an RPS with the schedule of at least 5% of load by January 1, 2011, at least 15% by January 1, 2015, at least 20 percent by January 1, 2020, and at least 25 percent by January 1, 2025.

In addition to its renewable energy focus, Oregon's proposed RPS also provides the framework for the further expansion of cost-effective conservation activity in the state by electric utilities. It allows the Commission to authorize an electric company to include in its rates the costs of funding or implementing cost-effective energy conservation measures beyond those currently funded through the state's public purpose charge—established under the state's restructuring legislation in 2002—and delivered by the Energy Trust of Oregon. If approved, Oregon's portfolio standard may allow conservation investments up to the potential conservation opportunity within the state, further adding to the demand-side resources available to address PacifiCorp's demand growth in the state.

Washington

In November 2006, Washington voters approved ballot initiative I-937[22], which would establish an RPS with the schedule of at least 3% of load by January 1, 2012, at least 9% by January 1, 2016, and at least 15% by January 1, 2020. The annual targets are based on the average of the utility's load for the previous two years. The Washington Utilities and Transportation Commission undertook rulemaking UE-061895 to effectuate the referendum.

Federal Renewable Portfolio Standard

Congress is expected to take up federal energy policy legislation, including the possibility of a federal RPS, as early as summer 2007. On the House side, Rep. Tom Udall (D-N.M.) has introduced legislation creating a 20% standard by 2020. Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-N.M.) has indicated he is planning legislation with a level of 15 percent by 2020.

The Senate has approved an RPS several times, most recently as part of the 2005 energy bill, but it died in conference with the House. Even so, environmentalists see the Democratic Congress as an opportunity for a host of initiatives that have failed in recent years. But the fate and timing of an RPS in the Energy and Commerce Committee, which has jurisdiction over the issue, is far from clear because a key committee leader and others have been skeptical of the need for an RPS.

TRANSMISSION PLANNING

Integrated Resource Planning Perspective

Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak load obligations are met on a reliable basis. With

[22] See, http://www.secstate.wa.gov/elections/initiatives/text/i937.pdf

this in mind, PacifiCorp's IRP team has increased its coordination with transmission planning personnel to more closely align long-term generation and transmission planning activities. The result for this IRP is a set of transmission resources for portfolio modeling that addresses PacifiCorp's control area needs as well as enables a first-cut evaluation of the impacts of a large multi-state transmission project. As discussed in the next section, PacifiCorp is engaged in a number of regional transmission planning initiatives intended to address transmission issues and project opportunities. Future IRP analysis efforts will be informed by these transmission planning initiatives.

Interconnection-Wide Regional Planning

Various regional planning processes have developed over the last several years in the Western Interconnection. It is expected that, in the future, these processes will be the primary forums where major transmission projects are developed and coordinated. In the Western Interconnection, regional planning has evolved into a two tiered approach where an interconnection-wide entity, Western Electricity Coordinating Council (WECC) conducts regional planning at a very high level and several sub-regional planning groups focus with greater depth on their specific areas.

Last year, WECC took on the responsibility for interconnection-wide transmission expansion planning. WECC's role in meeting the region's need for regional economic transmission planning and analyses is to provide impartial and reliable data, public process leadership, and analytical tools and services. The activities of WECC in this area are guided and overseen by a board-level committee, the Transmission Expansion Planning Policy Committee (TEPPC). TEPPC's three main functions include: (1) overseeing database management, (2) providing policy and management of the planning process, and (3) guiding the analyses and modeling for Western Interconnection economic transmission expansion planning. These functions compliment but do not replace the responsibilities of WECC members and stakeholders to develop and implement specific expansion projects.

TEPPC organizes and steers WECC regional economic transmission planning activities. Specific responsibilities include:

- steering decisions on key assumptions and the process by which economic transmission expansion planning data are collected, coordinated and validated;
- approving study plans, including study scope, objectives, priorities, overall methods/approach, deliverables, and schedules;
- steering decisions on analytical methods and on selecting and implementing production cost and other models found necessary;
- ensuring the economic transmission expansion planning process is impartial, transparent, properly executed and well communicated;
- ensuring that regional experts and stakeholders participate, including state/provincial energy offices, regulators, resource and transmission developers, load serving entities, environmental and consumer advocate stakeholders through a stakeholder advisory group;
- steering report writing and other communications that include communications between the TEPPC and the sub-regional planning groups;
- advising the WECC Board on policy issues affecting economic transmission expansion planning;

- recommending budgets for WECC's economic transmission expansion planning process;
- organizing and coordinate activities with sub-regional planning processes; and
- approving recommendations to improve the economic transmission expansion planning process.

TEPPC analyses and studies will focus on plans with west-wide implications and will include a high level assessment of congestion and congestion costs. The analyses and studies will also evaluate the economics of resource and transmission expansion alternatives on a regional, screening study basis. Resource and transmission alternatives may be targeted at relieving congestion, minimizing and stabilizing regional production costs, diversifying fuels, achieving renewable resource and clean energy goals, or other purposes. Alternatives may draw from state energy plans, integrated resource plans, large regional expansion proposals, sub-regional plans and studies, and other sources such as individual control areas if relevant in a regional context.

TEPPC's role does not include:

1. conducting sub-regional or detailed project-specific studies,
2. prioritizing and advocating specific economic expansion projects,
3. identifying potential "winners" and "losers,"
4. developing or advocating cost allocations,
5. developing or advocating cost allocation criteria,
6. providing mechanisms to obtain funding,
7. assigning transmission rights,
8. providing backstop permitting or approval authority, or
9. performing reliability analysis outside of what is being done today.

TEPPC includes transmission providers, policy makers, governmental representatives, and others with expertise in planning, building new economic transmission, evaluating the economics of transmission or resource plans; or managing public planning processes.

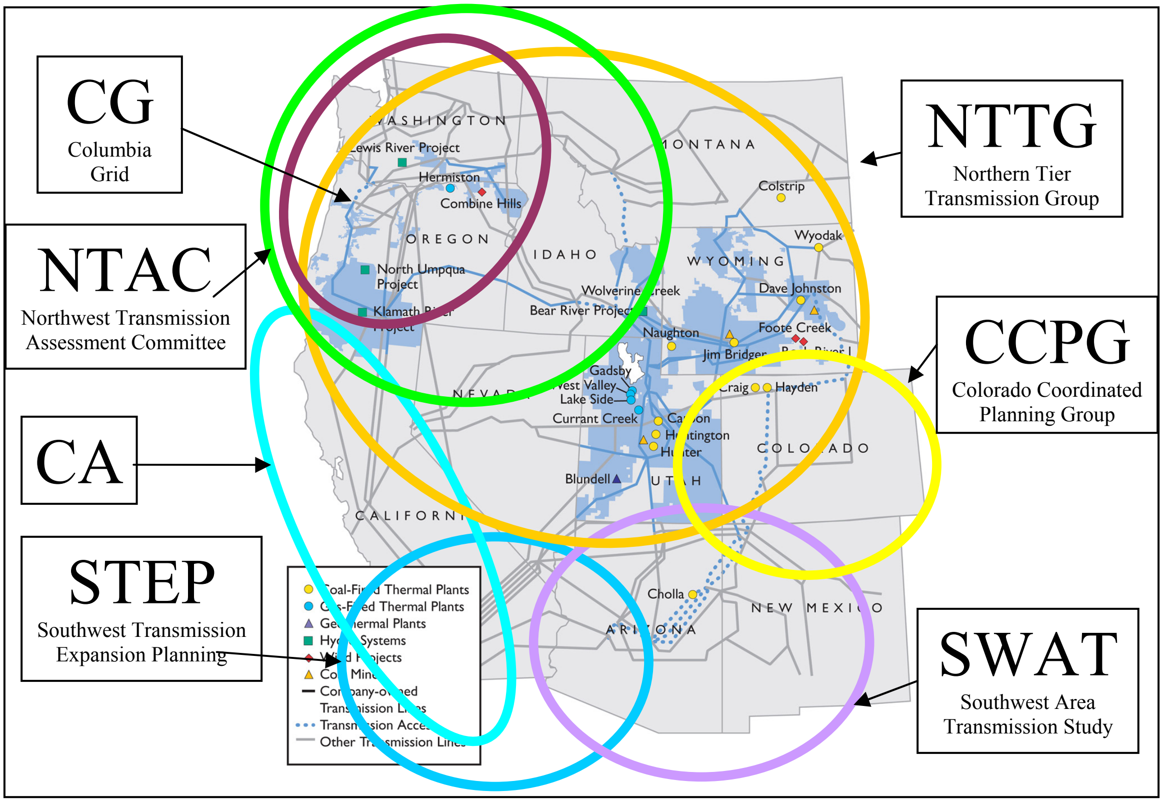
<u>Sub-regional Planning Groups</u>

Recognizing that planning the entire interconnection in one forum is impractical due to the overwhelming scope of the task, a number of smaller sub-regional groups have been formed to address specific problems in various areas of the interconnection. Generally all of these forums provide similar regional planning functions, including the development and coordination of major transmission plans within their areas. It is these sub-regional forums where the majority of transmission projects are expected to be developed. These forums will be informally coordinated with each other directly through liaisons and through TEPPC. A current list of sub-regional groups is provided below.

- CCPG – Colorado Coordinated Planning Group
- CG – Columbia Grid
- NTAC - Northwest Transmission Assessment Committee
- NTTG – Northern Tier Transmission Group
- STEP - Southwest Transmission Expansion Planning
- SWAT – Southwest Area Transmission Study

The geographical areas covered by these sub-regional planning groups are approximately as shown in Figure 3.1 below. In addition to the above groups, California is attempting to coordinate the overall planning for their state.

Figure 3.1 – Sub-regional Transmission Planning Groups in the WECC



HYDROELECTRIC RELICENSING

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

The value to relicensing hydroelectric facilities is continued availability of hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility as they can be called upon to meet peak customer demands almost instantaneously and provide back-up for intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation. Relicensing or decommissioning of many of PacifiCorp's projects are nearing completion as Federal Energy Regulatory Commission (FERC) licenses or Orders are expected to be issued for the majority of the portfolio over the next 1 to 3 years.

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

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

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and generally takes nearly ten or more years to complete, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2006, PacifiCorp had incurred $79.0 million in costs for ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As relicensing efforts continue, additional process costs are being incurred that will need to be recovered from customers. Also, new requirements contained in FERC licenses or decommissioning Orders could amount to over $2 billion over the next 30 to 50 years. Such costs include capital and operations and maintenance investments made in fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures as well as project operational changes such as increased in-stream flow requirements to protect fish resulting in lost generation. About 90 percent of these relicensing costs relate to PacifiCorp's three largest hydroelectric projects: Lewis River, Klamath River and North Umpqua.

Treatment in the IRP

The known or expected operational impacts mandated in the new licenses are incorporated in the projection of existing hydroelectric resources discussed in Chapter 4.

PacifiCorp's Approach to Hydroelectric Relicensing

As noted, PacifiCorp continues to manage this process by pursuing negotiated settlements as part of the relicensing process. PacifiCorp believes this proactive approach, which involves meeting agency and others' interests through creative solutions is the best way to achieve environmental improvement while managing costs. PacifiCorp also has reached agreements with licensing stakeholders to decommission projects where that has been the most cost-effective outcome for customers.

ENERGY POLICY ACT OF 2005

The Energy Policy Act of 2005 (EPAct), the first major energy law enacted in more than a decade, documents the tone of the current political/social environment. More than 1,700 pages long, the Act has hundreds of provisions. With respect to electric utilities the major provisions of the act include the following.

- Promote clean coal technology and provides incentives for renewable energy such as biomass, wind, solar and hydroelectricity and by requiring net metering options
- Encourage more hydropower production by improving current procedures for hydroelectric project licensing and calling for plans to improve the efficiency of existing projects.
- Requires state commissions to consider adopting five new standards dealing with net metering, interconnection, fossil fuel generation efficiency, time-based metering and telecommunication, and fuel sources.
- Provide for enforceable mandatory reliability standards, incentives for transmission grid improvements and reform of transmission siting rules. These improvements will attract new investment into the industry and ensure the reliability of our nation's electricity grid in order to stop future blackouts.
- Provides research and development support and a production tax credit for advanced nuclear power facilities

This section covers the major EPAct provisions that impact PacifiCorp and how the company is addressing them.

Clean Coal Provisions

The EPAct contains a number of provisions to encourage development of clean coal technologies. These provisions cover not only power generation technologies, but other coal-based technologies to encourage national energy security, reduced dependency on premium fossil fuels such as oil and natural gas, increased efficiency, and reductions in emissions. The primary focus of the clean coal provisions of the EPAct is on gasification, but other advanced technologies such as ultra-supercritical boiler technologies are also considered.

Under Title IV of the EPAct, financial assistance is made available to qualifying projects. The primary focus for the financial assistance is for advanced combustion systems and processes that reduce air pollution. Financial assistance can consist of cost sharing or loans.

Under Title XIII of the EPAct, a number of tax incentives are established. These incentives are primarily focused on development of gasification technologies both for electric power generation and coal-based gasification processes that produce liquid and gaseous fuels as well as primary chemical feedstocks. Available credits will be allocated on a first-come, first-served basis taking into account Department of Energy (DOE) balancing of the EPAct policy goals (fuel diversity, location, technology, CO_2 capture, project economics), i.e. integrated gasification combined cycle (IGCC) projects that include greenhouse gas capture, increase by-product utilization, and other benefits will be given high priority in the allocation of credits for IGCC projects.

Under the guidelines there are three separate application periods (2006, 2007, and 2008); the application date for each application period is June 30 of each year. Based on the overwhelming response the DOE received in 2006, the availability of investment tax credits (ITCs) is expected to diminish with time.

PacifiCorp submitted confidential applications on June 29, 2006 to the DOE for ITCs under this section of the Act for IGCC facilities at both the Hunter and Jim Bridger plant sites. PacifiCorp also indicated an interest in Energy Northwest's planned development of the Pacific Mountain Energy Center IGCC project. The proposed location for this project is in Port Kalama, Washington. Energy Northwest submitted a confidential application to the DOE for ITCs under this portion of the Act for that portion of the plant which would not be owned by public power entities.

Section 413 of EPAct also authorizes, subject to appropriations, funding support for a demonstration project to be built in the Western U.S. The Wyoming Infrastructure Authority (WIA) issued an RFP for a Wyoming Coal Gasification Demonstration Project on July 17, 2006. The WIA's intent for this RFP process was to identify one or more Wyoming based projects for the purpose of seeking Section 413 funding. PacifiCorp provided an expression of interest in response to this RFP on August 17, 2006, followed by a confidential proposal to the WIA in October 2006. As described in Chapter 5, the WIA recently selected PacifiCorp to participate in the joint IGCC project.

In addition to the ITC programs available for qualifying IGCC or advanced clean coal technologies, the EPAct makes available $350 million for ITCs for qualifying industrial gasification projects (not necessarily for power generation).

Title XVII of the EPAct provides for loan guarantees for innovative technologies, such as (IGCC) or technologies that reduce or sequester pollutants or greenhouse gases. PacifiCorp has reviewed the potential application of loan guarantees for potential IGCC projects under consideration and has determined that loan guarantees provide little value to the company and would entail significant regulatory complications.

Renewable Energy Provisions

The renewable energy production tax credit (PTC), which was set to expire at the end of 2005, was extended through the end of 2007. (The U.S. Congress extended it again through the end of 2008 as part of the Tax Relief and Health Care Act of 2006.) Additionally, the eligibility period for power production from open-loop biomass, geothermal, small irrigation, landfill gas and municipal solid waste projects is increased from 5 to 10 years. Finally, incremental hydropower production resulting from efficiency improvements or capacity expansion at existing dams was added to the list of production technologies eligible for the PTC.

PacifiCorp expects that extension of the PTC should aid the procurement of new wind and other renewable resources with a relatively short development lead-time. Nevertheless, dependence on year-to-year extensions represents a significant challenge for developing renewable resources with longer design/procure/construction periods, such as geothermal projects. Given the uncertain future of the PTC, PacifiCorp, along with other utilities, is attempting to acquire as much economic renewables as possible prior to the expiration date.

Hydropower

The bill includes a major reform of the federal licensing procedure for hydroelectric dams. The modifications allow an applicant to propose an alternative to mandatory conditions placed on hydropower licenses by federal resource agencies (Departments of Interior, Commerce and Agriculture). If a proposed alternative met the statutory environmental and resource protection standards, the alternative would be accepted. Hydro licensing reform has been a goal of the industry for years, but has been highly controversial with the environmental community.

The bill also includes incentives for improving the efficiency of existing hydroelectric dams and for modifying existing dams to produce electricity. (See Renewable Energy Provisions, above.)

Public Utility Regulatory Policies Act Provisions

The bill establishes market conditions necessary to eliminate the Public Utility Regulatory Policies Act's (PURPA) mandatory purchase obligation. The EPAct also includes amendments that establish market conditions that eliminate the requirement for utilities to buy power from independent renewable energy and cogeneration plants where FERC determines that competitive market conditions exist, and revises the criteria for new qualifying facilities seeking to sell power under the mandatory purchase obligation. Unfortunately, competitive markets may not support the long-term contracts that many renewable generators need to secure financing at affordable rates.

Title XII of EPAct also amends a section of PURPA by adding five new ratemaking standards for electric utilities. State regulatory commissioners are to determine whether the new standards are appropriate for their states. The five standards include net metering, fuel source diversity, fossil fuel generation efficiency and interconnection service to customers with their own on-site generating facilities.

Metering Provisions

Section 1252, "Smart Metering", of the EPAct requires that all utilities provide a time-based rate to all customer classes within 18 months of the enactment. In all states, PacifiCorp has met the basic requirements of the EPAct in regards to time-based rate schedule offerings.

Furthermore, the EPAct requires state commissions to conduct an investigation as to whether a time-based rate schedule and accompanying meter equipment is appropriate to implement and install within 18 months after date of enactment. The following time-based rates must be considered:

- "Time-of-use pricing" – Prices for specific periods and typically changed twice a year
- "Critical peak pricing" – Prices for peak days, discounts for reducing peak period consumption
- "Real-time pricing" – Prices may change hourly
- "Credits" – Large load customers who reduce a utility's planned capacity obligations

PacifiCorp has actively participated in all requested state commission investigations and/or technical conferences. These meetings must be completed by February 2007 with the commission recommendations provided by August 2007.

Section 110, "Daylight Savings", amends the Uniform Time Act of 1966 by extending Daylight Savings Time (DST) by four weeks beginning in 2007. DST will begin the second Sunday of March and end the first Sunday of November. This section also requires the Department of Energy to file a report to Congress nine months after enactment on the impact of this section on energy consumption in the U.S. Congress retains the right to revert DST back to the 2005 time once the report is complete.

To meet the requirements of Section 110, all of PacifiCorp's time-of-use and interval meters would be required to be replaced and/or reprogrammed to align the internal calendars with the new dates. With the possibility of Congress reverting to 2005 time, the exposure for cost to reprogram the meters is significant.

To mitigate the costs of meter replacement and programming until such time as a formal decision is made, PacifiCorp has filed, or will be filing, interim tariff modifications in all states. If accepted, the modifications will keep the existing 2005 DST dates within the applicable tariffs until such time that a formal decision is made. PacifiCorp will comply with the requirements of the decision at that time.

Fuel Source Diversity
Section 111(d)(12), "Fuel Sources", requires electric utilities to develop "a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies." Within three years of enactment, state regulatory authorities must decide whether to enact this standard or determine that a comparable standard meets this objective.

During 2006, PacifiCorp reviewed this amendment with states and other interested parties through technical conferences sponsored by the state commissions. PacifiCorp believes that the state IRP standards and guidelines reflect a comparable standard that fulfills the requirement for a fuel source diversity plan. The Public Service Commission of Utah concurred with this view, issuing a determination that the current Utah IRP guidelines constitute a comparable standard.[23] During the October 17, 2006 technical conference, the company agreed to include a section in the IRP that discusses how fuel diversity is addressed in the planning process. This section is included in Chapter 8, "Action Plan."

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[23] Public Service Commission of Utah, "Determination Concerning the PURPA Fuel Sources Standard" (Docket No. 06-999-03), issued March 13, 2007.

Fossil Fuel Generation Efficiency Standard

The PURPA amendments include a requirement that each electric utility develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation plants. States must determine whether to adopt this standard by August 8, 2008. States do not have to comply if the state has already adopted or considered a comparable provision.[24] PacifiCorp has been reviewing this amendment with states and other interested parties through technical conferences sponsored by the state commissions. PacifiCorp believes that the IRP currently serves as a comparable provision with respect to fleet efficiency improvements arising from new generation and retirement of old, less efficient fossil units.

In discussions with Utah Public Service Commission staff, PacifiCorp agreed to report in this IRP the 20-year forecasted average heat rate trend for the company's fossil fuel generator fleet. This forecasted average heat rate represents the individual generator heat rates weighted by their annual generation, accounting for new IRP resources and current planned retirements of existing fossil fuel generators. For existing fossil fuel resources, four-year average historical heat rate curves are used, whereas new resources use expected heat rates accounting for degradation over time. This fleet-wide heat rate trend information is provided in Figure 7.34 in Chapter 7, "Results."

In PacifiCorp's subsequent integrated resource plans, the company will summarize its efficiency improvement plans, as well as report heat rate trends using forward-looking heat rates that account for these plans.

Transmission and Electric Reliability Provisions

This portion of the EPAct is intended to:

- Help ensure that consumers receive electricity over a dependable, modern infrastructure;
- Remove outdated obstacles to investment in electricity transmission lines;
- Make electric reliability standards mandatory instead of optional; and
- Give Federal officials the authority to site new power lines in DOE-designated national corridors in certain limited circumstances.

Two sections of this legislation pertain specifically to the development of major new transmission lines: Section 368a, which defines "energy corridors", and Section 1221, which attempts to identify and address transmission congestion.

Section 368a, Energy Corridors

Section 368a directs the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior (the Agencies) to designate under their respective authorities corridors on Federal land in the 11 Western States for oil, gas and hydrogen pipelines and electricity transmission and distribution facilities (energy corridors). The legislation sets the timetable for corridor designation in the eleven Western States at no later than two (2) years after enactment, or August 2007.

[24] Edison Electric Institute, *Energy Policy Act of 2005, Summary of Title XII – Electricity, Title XVIII – Studies, and Related Provisions* (August 3, 2005), page 10.

The Agencies determined that designating corridors as required by Section 368a of the Act constitutes a major Federal action which may have a significant impact upon the environment within the meaning of the National Environmental Policy Act (NEPA). For this reason, the Agencies are preparing a draft Programmatic Environmental Impact Statement (PEIS) to identify the impacts associated with designating energy corridors. Based upon the information and analyses developed in the PEIS, the Agencies will designate energy corridors by amending their respective land use plans.

Public scoping meetings were held in October and November 2005. Potential energy corridor locations were depicted on draft maps and circulated for comment (See the following DOE web site for these maps: http://corridoreis.anl.gov/eis/pdmap/index.cfm). The draft PEIS was released for comments last fall. Final energy corridors will be identified in the final EIS which is scheduled to be released in August 2007. The majority of the preliminary energy corridors utilize existing corridors and/or rights-of-way; however, there are a small number of potential new corridor locations.

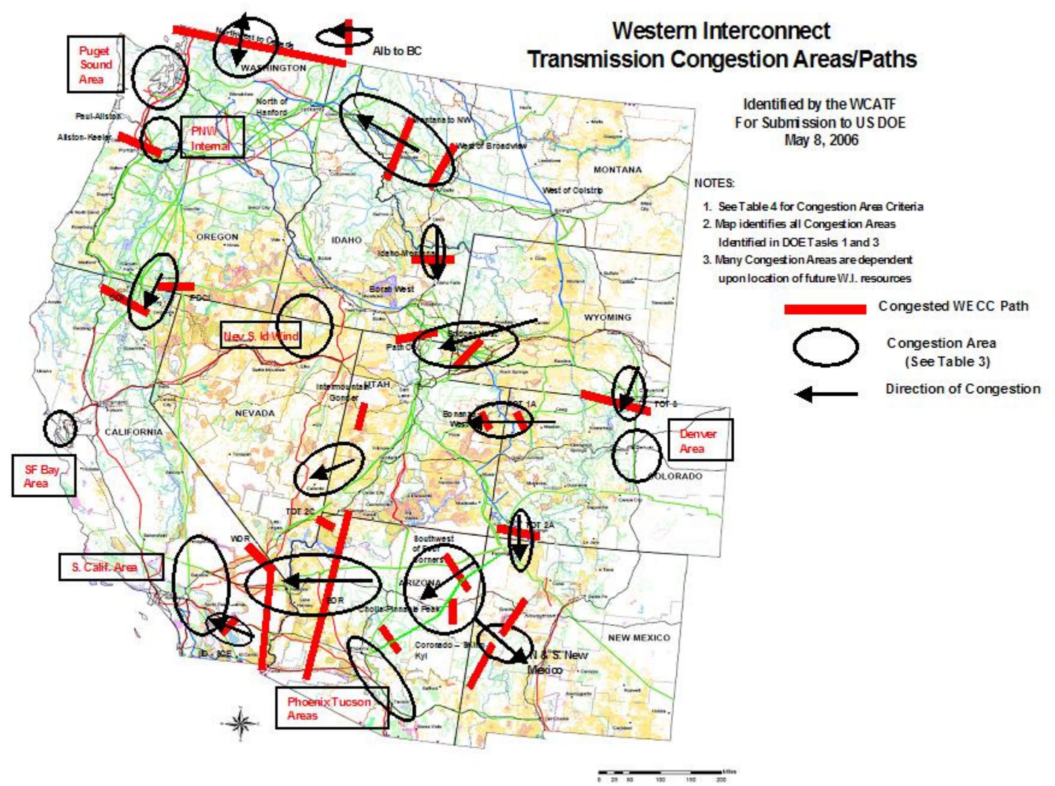
Section 1221, National Transmission Congestion Study

Section 1221 of the EPAct of 2005 required DOE to issue a national transmission congestion study for comment by August 2006 and every three years thereafter. Based on the study and public comments, DOE may designate selected geographic areas as "National Interest Electric Transmission Corridors." Applicants for projects proposed within designated corridors that are not acted upon by state siting authorities within one year may request FERC to exercise federal "backstop" siting authority. For the Western Interconnection, DOE relied on the Western Congestion Assessment Task Force (WCATF), which is an ad-hoc group formed primarily by WECC members, to complete the congestion study. The WCATF produced several work products for DOE including a summary of major studies, a report describing historical congestion, and the results of SSG-WI production cost studies conducted for the years 2008 and 2015. Figure 3.2 is a map provided to DOE showing the major areas of congestion in the Western Interconnection.

Based on the WCATF report and other information, the DOE produced a national transmission congestion report that shows congested areas across the Western Interconnection. The only critical congestion area highlighted in the Western Interconnection was in southern California. In addition to the congestion in southern California, it was noted that there are conditional constraints in the PacifiCorp area in association with exporting potential new coal and wind resources from the states of Montana and Wyoming (See Figure 3.3)

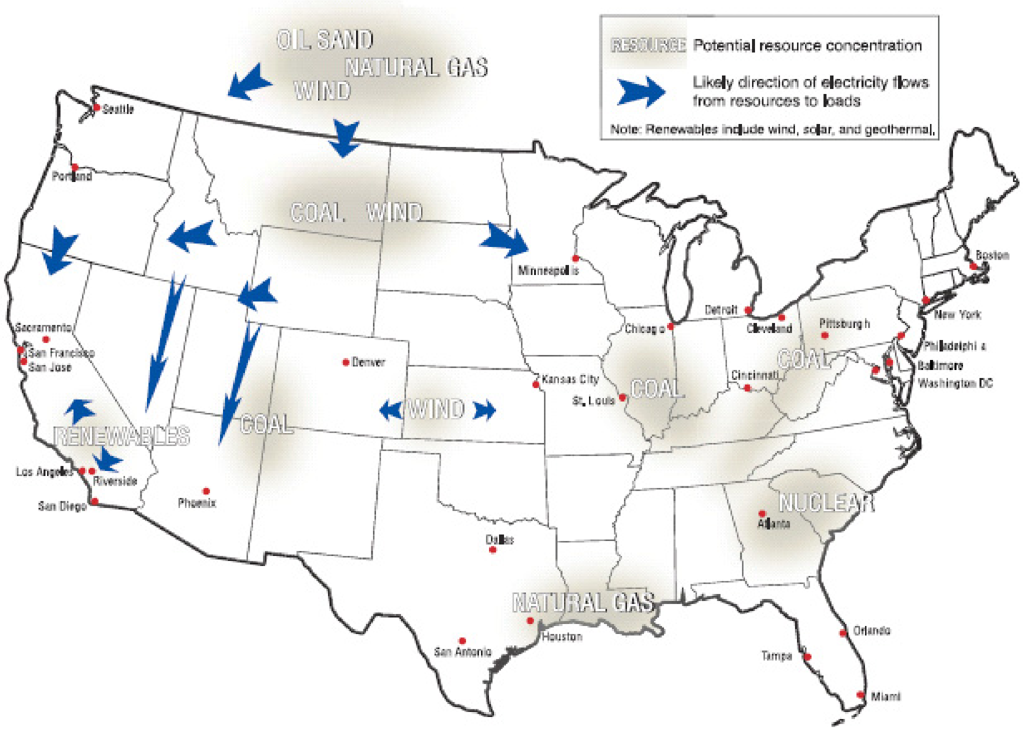
The effect of Section 1221 on PacifiCorp is unclear at this point, but it is expected to be beneficial as it should speed up the permitting process for new transmission facilities.

Figure 3.2 – Western Interconnection Transmission Congestion Areas/Paths



Source: Western Congestion Analysis Task Force, *Western Interconnection Congestion Areas: Summary Tables 1, 2 and 3 with Congestion Area Map*, prepared for the U.S. Department of Energy, May 8, 2006.

Figure 3.3 – Conditional Constraint Areas



Source: U.S. Department of Energy, *National Electric Transmission Congestion Study*, August, 2006.

<u>Climate Change</u>

The EPAct established a Climate Change Technology Advisory Committee to identify statutory, regulatory, economic and other barriers to the commercialization and deployment of technologies and practices that would reduce the intensity of greenhouse gas production. Additionally, the new law directs the State Department to act as lead agency for integrating into U.S. foreign policy the goal of reducing greenhouse gas intensity in developing countries, and directs DOE to conduct an inventory of greenhouse gas intensity reducing technologies for transfer to developing countries.

RECENT RESOURCE PROCUREMENT ACTIVITIES

Supply-Side Resources

2012 Request for Proposals for Base Load Resources
As a consequence of the update to the 2004 Integrated Resource Plan (filed in November 2005), PacifiCorp suspended the 2009 Request for Proposal and is preparing a new RFP for acquisition of east-side base load resources for 2012, 2013, and 2014.

The base load RFP seeks to acquire up to 1,700 megawatts of cost-effective resources for the term of 2012 through 2014, consisting of a combination of generation assets, generation assets on the company's sites and market purchases (i.e., front office transactions).[25] The company has included two benchmark resources in the RFP. The benchmark resource for 2012 is 340 megawatts, representing the Intermountain Power Plant Unit 3 and the benchmark resource for 2014 is 575 megawatts, representing Bridger 5. The company issued its base load RFP on April 5, 2007.

Renewables Request for Proposal 2003B
PacifiCorp amended the renewables Request for Proposal 2003B in March 2006 to assist in meeting renewable procurement targets, including those related to the MidAmerican transaction commitment to acquire economic renewable resources. As a result of the bids received, PacifiCorp considered nearly twenty competing offers.

Demand-side Resources

The 2005 DSM RFP to procure Class 1, 2 and 3 resources was issued according to the action plan in the 2004 IRP (See 2004 IRP, Table 9.3). The RFP was structured to solicit proposals for both specific resources types—for example, comprehensive residential equipment and service program—as well as an "all comers" request for each resource type. The most notable program addition originating from the 2005 DSM RFP is the Home Energy Savers program, filed and approved in 2006 in Idaho, Washington and Utah, and, pending commission approval, to be offered in California and Wyoming in 2007. The company also accepted a proposal to enhance business program penetration of the new construction market. In addition, there remain a select few program proposals from the 2005 DSM RFP that may be pursued provided the Company receives supporting information through their system-wide demand-side management potential study indicating that sufficient opportunity, customer interest, and delivery price points exist to support the proposals. The system-wide demand-side management potential study, a MidAmerican Energy Holdings Company commitment made during its acquisition of PacifiCorp in March 2006, is scheduled to be completed in June 2007. The Company intends to use the information from this study to assist in the refinement of their current demand-side programs (expand and improve their performance) as well as identify additional cost-effective and system relevant program opportunities across all program types, e.g., energy efficiency, demand control or management, and demand response.

[25] The RFP covers power purchase agreements, tolling service agreements, asset purchases, load curtailment contracts, and Qualifying Facility contracts. See Chapter 4, Action Plan, for more details concerning the Base Load RFP.

THE IMPACT OF STATE RESOURCE POLICIES ON SYSTEM-WIDE PLANNING

A new planning issue that PacifiCorp is dealing with for this IRP cycle is the rapid evolution of state-specific resource policies that place, or are expected to place, constraints on PacifiCorp's resource selection decisions. As discussed earlier in this chapter, these policies cover CO_2 emissions, renewable energy, energy efficiency, load control, distributed generation, and the promotion of advanced clean coal and carbon sequestration technologies. Table 3.1 represents an inventory of state policy actions and events that occurred in 2006, and so far in 2007, that impact PacifiCorp's integrated resource planning process now and in the future.

Considerable complexity is added to system-wide resource planning and the supporting modeling process as a result of these policies. In addition, disparate state interests, as expressed in prior IRP acknowledgement proceedings and throughout the 2007 IRP development cycle, complicates the company's ability to address state IRP requirements to the satisfaction of all stakeholders.

Table 3.1 – State Resource Policy Developments for 2006 and 2007

2006	2007
January: Oregon PUC, in its 2004 IRP acknowledgement order, does not acknowledge a near-term "high-capacity-factor" resource, and requires that PacifiCorp explore coal deferral options until IGCC is commercialized	**January:** The California PUC adopts a greenhouse gas emission performance standard for generators
January: Oregon PUC rejects the 2004 IRP Update Action Plan	**January:** The Oregon PUC rejects PacifiCorp's 2012 RFP
February: Oregon Renewable Energy Working Group is formed	**January:** The Oregon Carbon Allocation Task Force recommends a CO_2 load-based cap-and-trade model rule
March: Oregon, California, and Washington join other petitioners in asking the U.S. Supreme Court whether the U.S. Environmental Protection Agency has the authority to regulate carbon dioxide and other air pollutants associated with climate change	**February:** The Washington Governor signs Executive Order 07-02 setting climate change-related rules, including greenhouse gas emissions caps
April: Idaho moratorium on coal-fired plants is issued.	**February:** Washington introduces legislation setting carbon caps and a GHG emissions performance standard
August: Utah Blue Ribbon Advisory Council on Climate Change formed	**February:** the Western Regional Climate Change Action Initiative announced by California, Oregon, Washington, New Mexico, and Arizona
September: California adopts a carbon cap (AB 32)	**February:** Utah, Wyoming, Nevada, and North Dakota announce the NextGen Energy Alliance, which is to promote ad-

2006	2007
	vanced coal technologies and economic utilization of carbon dioxide
November: the Oregon governor announces a renewable portfolio standard plan	**March:** Oregon RPS and carbon-related legislation introduced (a cap and greenhouse gas emissions performance standard)
November: Washington adopts a renewable portfolio standard	**April:** The U.S. Supreme ruled that the EPA has the authority to regulate CO_2 emissions
December: Western Public Utility Commission Joint Action Framework on Climate Change (California, Oregon, Washington, New Mexico) launched	
December: The Utah PSC issues suggested modifications to PacifiCorp's 2012 base load RFP	

4. RESOURCE NEEDS ASSESSMENT

Chapter Highlights

- On an energy basis, PacifiCorp expects a system-wide average load growth of 2.5 percent per year from 2007 through 2016. Wyoming shows the largest load growth over the 2007 to 2016 at 5.6 percent average annual rate. Utah load is projected to grow at an average annual rate of about 3 percent, while the other states where the company operates—Oregon, Washington, Idaho, and California—have load growth projected at about 1 percent.

- System peak load is expected to grow at a faster rate than overall load due to the changing mix of appliances over time. PacifiCorp's eastern system peak is expected to continue growing faster than its western system peak, with average annual growth rates of 3.2 percent and 0.8 percent, respectively, over the forecast horizon.

- PacifiCorp anticipates a system peak resource capacity of 12,131 megawatts for the summer of 2007.

- Near-term resource changes include the following:
  - Conversion of the Currant Creek facility from a single cycle combustion turbine to a combined cycle combustion turbine (June 2006)
  - The addition of the Lake Side combined cycle combustion turbine (expected commercial operation in June 2007)
  - The addition of the Leaning Juniper 1 and Marengo wind projects
  - Expiration of the 400-megawatt power purchase agreement with TransAlta Energy Marketing expires in June 2007
  - Expiration of the 575 megawatt BPA peaking contract in August 2011
  - Expiration of the West Valley plant lease in May 2008

- On both a capacity and energy basis, load and resource balances are calculated using existing resource levels, obligations, and reserve requirements. Contract expirations also impact these calculations.

- The company projects a summer peak resource deficit for the PacifiCorp system beginning in 2008 to 2010, depending on the capacity planning reserve margin assumed. Beginning in 2009, the company becomes energy deficient on an annual basis.

- The PacifiCorp deficits prior to 2011 to 2012 will be met by additional renewables, demand side programs, and market purchases. Then beginning in 2011 to 2012, base load, intermediate load, or both types of resource additions will be necessary to cover the widening capacity and energy deficits.

INTRODUCTION

This chapter presents PacifiCorp's assessment of resource need, focusing on the first 10 years of the IRP's 20-year study period, 2007 through 2016. The company's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are addressed first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are comprised of a year-by-year comparison of projected loads against the resource base without new additions. This comparison indicated when PacifiCorp is expected to be either deficit or surplus on both a capacity and energy basis for each year of the planning horizon.

LOAD FORECAST

Methodology Overview

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.[26] Appendix A provides additional details on methodologies and state level forecasts.

Integrated Resource Planning Load Forecasts

Through the course of the 2007 integrated resource planning cycle, PacifiCorp relied on two load forecasts for the development of the load and resource balance and portfolio evaluations. The first official load forecast used in this IRP cycle, released in May 2006, was used to support portfolio analysis from May 2006 to February 2007. Between May 2006 and March 2007, events transpired that resulted in the need to revise the load forecast. Because of the magnitude of the forecast changes and the extended IRP filing schedule granted by the state commissions, the company decided that it was prudent to incorporate load forecast updates in the IRP. Consequently, PacifiCorp's IRP analysis from February 2007 onward reflects the new March 2007 load forecast.

The primary changes to the original May 2006 load forecast result from recent trends and conditions on the east side of PacifiCorp's service territory. Growth in Utah was slowing from what was previously planned; therefore, its growth rates were reduced. This was mainly associated with the growth in the commercial class and a slowing of the service activity in the state. Offsetting this were requests for service in the oil and gas industries of Wyoming. Higher prices, fuel supply uncertainty both nationally and worldwide resulted in plans to increase the development of the fields in Wyoming. Additionally, portions of Wyoming are experiencing air quality problems with existing extraction practices that require electrification of the existing services in the

[26] 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.

fields. The load requests from customers in these areas total over 1,000 megawatts in 2012. While these state trends largely offset each other on a total projected load basis, the revised Wyoming load growth affects the timing of the resource need. That is why the company decided to incorporate the new load forecast in the IRP.

The following sections describe the March 2007 energy and coincident peak load forecasts, as well as summarize the differences with respect to the original May 2006 forecast.

Energy Forecast

Table 4.1 shows average annual energy load growth rates for the PacifiCorp system and individual states. Growth rates are shown for the historical period 1995 through 2005, and the forecast period 2007 through 2016.

Table 4.1 – Historical and Forecasted Average Energy Growth Rates for Load

Average Annual Growth Rate	Total	OR	WA	WY	CA	UT	ID
1995-2005	**1.6%**	0.1%	1.4%	1.4%	1.3%	3.0%	1.3%
2007-2016	**2.4%**	0.6%	1.3%	5.6%	1.1%	2.7%	1.0%

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.4 percent annually from fiscal year 2007 to 2016. This is slightly faster than the average annual historical growth rate experienced from 1995 to 2005. During this historical period the total load for these states increased at an average annual rate of 1.6 percent. Table 4.2 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 4.2 – Annual Load Growth in Megawatt-hours for 2006 and forecasted 2007 through 2016

Year	Total	OR	WA	WY	CA	UT	ID
2006	**58,466,744**	15,388,512	4,637,218	8,818,396	991,346	22,958,123	5,673,149
2007	**58,244,203**	14,745,256	4,556,816	9,043,776	944,252	23,407,514	5,546,589
2008	**60,003,127**	14,774,141	4,577,294	10,035,331	948,959	24,070,475	5,596,927
2009	**61,824,270**	14,813,056	4,608,889	11,157,044	953,801	24,653,183	5,638,297
2010	**63,939,431**	14,927,068	4,821,004	12,019,398	979,509	25,494,009	5,698,443
2011	**65,638,416**	15,041,955	4,900,526	12,842,214	988,843	26,114,702	5,750,176
2012	**67,027,436**	15,157,677	4,944,106	13,347,838	998,372	26,767,715	5,811,728
2013	**68,304,861**	15,274,258	4,988,967	13,718,417	1,008,170	27,453,851	5,861,198
2014	**69,525,861**	15,391,817	5,033,291	13,991,101	1,018,178	28,175,184	5,916,290
2015	**70,776,423**	15,510,250	5,077,689	14,245,983	1,028,365	28,938,113	5,976,023
2016	**72,305,522**	15,629,572	5,125,690	14,712,173	1,038,612	29,745,665	6,053,810
AAG 2007-2016	**2.4%**	0.6%	1.3%	5.6%	1.1%	2.7%	1.0%
AAG 2016-2026	**2.0%**	1.3%	1.3%	2.0%	1.6%	2.7%	1.1%

As can be seen from the average annual growth rates at the bottom of the Table 4.2, the eastern system continues to grow faster than the western system, with an average annual growth rate of 3.2 percent and 0.8 percent, respectively, over the forecast horizon.

System-Wide Coincident Peak Load Forecast

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 in Appendix A. 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.

The system peak load is expected to grow from the 2005 peak of 8,937 megawatts at a faster rate than overall load due to the changing mix of appliances over time. Table 4.3 shows that for the same time period the total peak is expected to grow by 2.6 percent. The system peak, which previously occurred in the winter, has switched to the summer as a result of these changes in appliance mix. The change in seasonal peak is due to an increasing demand for summer space conditioning in the residential and commercial classes and a decreasing demand for electric related space conditioning in the winter. This trend in space conditioning is expected to continue. Therefore, the disparity in summer and winter load growth will result in system peak demand growing faster than overall load. However, once the demand in space conditioning equipment stabilizes, the total load and system peak growth rates should equalize.

Table 4.3 – Historical and Forecasted Coincidental Peak Load Growth Rates

Average Annual Growth Rate	Total	OR	WA	WY	CA	UT	ID
1995-2005	**1.9%**	(1.1)%	(1.0)%	(0.9)%	1.9%	7.3%	5.8%
2007-2016	**2.6%**	1.2%	1.2%	5.8%	1.2%	2.9%	1.2%

Again, PacifiCorp's eastern system peak is expected to continue growing faster than its western system peak, with average annual growth rates of 3.2 percent and 1.2 percent, respectively, over the forecast horizon. This is similar to historical growth patterns as Table 4.3 reflects. East system peak growth during this time has been faster than west system peak growth. Of course, peak growth is somewhat masked in Table 4.3 if you consider that the peak has shifted from winter months to summer months.

Table 4.4 shows the average annual coincidental peak growth occurring in the summer months for 1995 through 2005. This shows that some of what appears to be a decrease in peak load in many states is due to the shift from winter to summer, and that growth in peak is truly occurring. It also shows that faster growth is continuing to occur in the eastern portion of the system where average historical growth has been 2.8 percent, while the western portion of the system grew at 1.1 percent on average. This pattern is expected to continue as discussed previously.

Table 4.4 – Historical Coincidental Peak Load - Summer

Average Annual Growth Rate	Total	OR	WA	WY	CA	UT	ID
1995-2005	2.2%	0.8%	1.7%	0.0%	2.2%	5.2%	1.5%

The system peak load is expected to grow at a slightly faster rate than the overall load due to the changing mix of appliances over time. Table 4.5 below shows that for the same time period the total peak is expected to grow by 2.6 percent. Until recently, the system peak occurred in the winter months. Due to a 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, the system peak has started occurring in summer months. PacifiCorp expects 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 mix ends.

Table 4.5 – Forecasted Coincidental Peak Load in Megawatts

Year	Total	OR	WA	WY	CA	UT	ID	SE-ID
2006	**9,577**	2,684	816	1,094	156	4,011	561	256
2007	**9,243**	2,076	699	1,044	147	4,298	632	347
2008	**9,440**	2,075	702	1,145	147	4,409	631	331
2009	**9,752**	2,235	702	1,282	159	4,420	678	276
2010	**10,261**	2,254	729	1,416	141	4,720	696	305
2011	**10,488**	2,314	757	1,473	128	4,932	573	311
2012	**10,836**	2,320	766	1,569	155	4,973	686	367
2013	**10,989**	2,328	767	1,613	156	5,061	693	371
2014	**11,157**	2,331	773	1,648	158	5,184	708	355
2015	**11,296**	2,326	774	1,669	171	5,337	719	300
2016	**11,619**	2,314	775	1,733	163	5,547	745	342
AAG 2007-2016	**2.6%**	1.2%	1.2%	5.8%	1.2%	2.9%	1.8%	-0.2%
AAG 2016-2026	**2.2%**	1.5%	1.6%	1.9%	0.4%	2.9%	1.4%	1.0%

One noticeable aspect of the states contribution to the system coincidental peak forecast is that they do not continuously increase from year to year, even though the total system peak and each state's individual peak loads generally increase from year to year. This behavior occurs because state level coincident peaks do not occur at the same time as the system level coincident peak, and because of differences among the states with regard to load growth and customer mix. While each state's peak load is forecast to grow each year when taken on its own, its contribution to the system coincident peak will vary since the hour of system peak does not coincide with the hour of peak load in each state. As the growth patterns of the class and states change over time, the peak will move within the season, month or day, and each state's contribution will move accordingly, sometimes resulting in a reduced contribution to the system coincident peak from year to year in a particular state. This is seen in a few areas in the forecast as well as experienced in history. For example, the Idaho state load is driven in the summer months by the activity in the irrigation class. The planting and irrigating practices usually cause this state to experience the maximum load in late June or early July. This load then quickly decreases week by week. Consequently, there can be as much as 150 megawatts of load difference between the maximum load and the loads during the last weeks of July. This anomaly can be seen when comparing the Idaho contribution to the system coincident peak in 2010 and 2011.

Another noticeable aspect is the decline in the loads from the actual period to the first forecast year. This is noticeable in Oregon when the 2007 is compared to the 2006 value. There may be several things that can impact this. In the Oregon case, a large industrial customer is expected to cease operations during 2007. This large customer and the associated multiplier effect of this customer will cause a decline in load for Oregon. Other factors contributing to the decline include the changing time of the system peak demand in 2007, variability in jurisdictional contribution to the peak demand over time, and weather effects to the Oregon contribution in 2006.

Jurisdictional Peak Load Forecast

The economies, industry mix, appliance and equipment adoption rates, and weather patterns are different for each jurisdiction that PacifiCorp serves. Because of these differences the jurisdictional hourly loads have different patterns than the system coincident hourly load. In addition, the growth for the jurisdictional peak demands can be different from the growth in the jurisdictional contribution to the system peak demand. Table 4.6 reports the historical growth rates for each of the jurisdictional peak demands, while Table 4.7 reports the jurisdictional peak demand growth over the forecast horizon.

Table 4.6 – Historical Jurisdictional Peak Load

Average Annual Growth Rate	OR	WA	WY	CA	UT	ID
1995-2005	0.6%	0.7%	-0.4%	0.6%	4.4%	1.9%

Table 4.7 – Jurisdictional Peak Load in Megawatts for 2006 and forecast 2007 through 2016

Year	OR	WA	WY	CA	UT	ID
2006	2,730	818	1,208	179	4,357	723
2007	2,393	751	1,185	191	4,347	678
2008	2,405	744	1,372	190	4,409	680
2009	2,457	750	1,572	194	4,483	736
2010	2,455	782	1,627	199	4,791	755
2011	2,472	795	1,681	201	4,932	770
2012	2,536	807	1,757	200	5,044	747
2013	2,533	807	1,778	205	5,172	757
2014	2,541	805	1,817	207	5,267	770
2015	2,552	808	1,844	209	5,416	780
2016	2,536	803	1,908	208	5,658	811

Year	OR	WA	WY	CA	UT	ID
AAG 2007-2016	0.6%	0.7%	5.4%	1.0%	3.0%	2.0%
AAG 2016-2026	1.4%	1.5%	1.9%	1.8%	3.0%	0.9%

Additional detailed information about the load forecast can be found in Appendix A, Base Assumptions.

May 2006 Load Forecast Comparison

Tables 4.8 and 4.9 show the respective state annual peak load and energy differences between the March 2007 forecast and those for the May 2006 forecast. The impacts of slowing service activity in Utah and greater forecasted demand in Wyoming mentioned above are evident for both capacity and energy trends. For example, Utah continues to have one of the strongest economies in the nation and will likely continue to do so; however, there have been subtle signs of some slowing of very robust growth. As published in the Salt Lake City Tribune[27], the Utah Department of Workforce Services reported job growth of 4.5 percent for the year that ended in March 2007, which is down significantly from a peak of 5.4 percent in June 2006. An additional indicator of slightly slowing growth is in residential building permits in Utah, which declined by 6.9 percent in 2006 from the 2005 level. Statistics from the Bureau of Economic and Business Research at the University of Utah continue to show slowing when compared to 2006 through February 2007. This trend is also evident in PacifiCorp sales growth in Utah from 2006 into 2007. Taken together, these trends helped drive the slight slowing of the peak growth from a 3.0 percent average annual growth rate from 2007 to 2016 in the May 2006 forecast to a 2.9 percent average annual growth in the March 2007 forecast. From an energy perspective, the average annual load growth rate from 3.0 percent in the May 2006 forecast decreased to a 2.7 percent average annual growth rate for 2007 to 2016 in the March 2007 forecast.

Regarding the energy forecast difference for Oregon, the March 2007 forecast is based on an expected lower growth rate for residential electric heating usage. This lower usage is causing an impact on energy while the coincident peak demand remains relatively unchanged. In addition, long-term industrial retail sales are expected to be lower due to a further deterioration in the paper products and lumber industries in the west. This deterioration has less of an impact on peak, weather responsive demand than on total energy.

Table 4.8 – Changes from May 2006 to March 2007: Forecasted Coincidental Peak Load (Megawatts)

Year	Total	OR	WA	WY	CA	UT	ID
2007	(182)	1	(41)	(76)	(2)	(43)	(21)
2008	(338)	(36)	(36)	(23)	(4)	(216)	(23)
2009	(273)	24	6	(107)	13	(254)	45

[27] Mitchell, Lesley. "Utah's job growth rate stays ahead of nation." Salt Lake City Tribune. April 17, 2007. http://www.sltrib.com/search/ci_5691499

Year	Total	OR	WA	WY	CA	UT	ID
2010	**17**	72	48	(17)	13	(53)	(46)
2011	**7**	19	50	1	(21)	(13)	(29)
2012	**213**	78	75	88	14	22	(64)
2013	**170**	57	69	115	14	(20)	(65)
2014	**140**	36	67	140	14	(56)	(61)
2015	**82**	(33)	49	165	16	(167)	52
2016	**105**	(104)	40	204	6	(140)	99
AAG 2007-2016	**0.3%**	(0.5)%	1.2%	2.3%	0.6%	(0.2)%	2.0%
AAG 2016-2026	**(0.3)%**	0.5%	0.1%	0.8%	(1.6)%	(0.9)%	(0.1)%

Table 4.9 – Changes from May 2006 to March 2007: Forecasted Load Growth (Average Megawatts)

Year	Total	OR	WA	WY	CA	UT	ID
2007	**(49)**	1	4	(21)	(1)	(25)	(8)
2008	**(101)**	(34)	7	1	(1)	(67)	(7)
2009	**(70)**	(12)	(9)	26	(1)	(62)	(13)
2010	**(4)**	(20)	12	80	1	(65)	(12)
2011	**60**	(26)	18	152	1	(75)	(10)
2012	**74**	(33)	18	192	1	(93)	(11)
2013	**84**	(40)	19	222	0	(107)	(11)
2014	**85**	(47)	19	242	0	(117)	(12)
2015	**109**	(55)	19	277	0	(121)	(11)
2016	**128**	(67)	17	315	(0)	(126)	(12)
AAG 2007-2016	**0.3%**	(0.4)%	0.3%	2.6%	0.0%	(0.3)%	(0.1)%
AAG 2016-2026	**0.1%**	0.0%	(0.1)%	1.0%	(0.2)%	0.0%	(0.2)%

EXISTING RESOURCES

In 2007 PacifiCorp owns, or has interest in, resources with a system peak capacity of 12,131 megawatts. Table 4.10 provides anticipated system peak capacity ratings by resource category as of July 2007.

Table 4.10 – Capacity Ratings of Existing Resources

Resource Type	MW*	Percent
Pulverized Coal	6,097	50.3%
Purchases**	1,836	15.1%
Gas-CCCT	1,698	14.0%

Resource Type	MW*	Percent
Gas-SCCT	385	3.2%
Hydroelectric	1,556	12.8%
Interruptible	233	1.9%
Renewable***	173	1.4%
Class 1 DSM	153	1.3%
Total	**12,131**	**100%**

* Represents the capacity available at the time of system peak.
** Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.
*** Renewables capacity reflects the capacity contribution at the time of peak load.

Thermal Plants

In June 2006, the company converted the Currant Creek facility from a single cycle combustion turbine to a combined cycle combustion turbine, which increased the capability of the plant by 231 megawatts. The Lake Side combined cycle combustion turbine is expected to begin commercial operation in June 2007, adding 535 megawatts of additional capacity to the system. The lease for the West Valley plant expires in May 2008, reducing the company's total thermal plant capacity by 202 megawatts. Appendix A, Table A.12, provides operational characteristics of thermal plants and other generation resources for which PacifiCorp has an ownership interest.

Renewables

PacifiCorp is committed to renewable energy resources as a viable, economic and environmentally prudent means of generating electricity. PacifiCorp's renewable resources, presented by resource type, are described below.

Wind

PacifiCorp acquires wind power from PacifiCorp-owned wind plants and various purchase agreements. For the year ended December 31, 2006, PacifiCorp received 118,610 megawatt-hours from an owned wind project. In the same period, 394,973 megawatt-hours were purchased from other wind projects.

Since the 2004 Integrated Resource Plan, PacifiCorp has acquired large wind resources at Leaning Juniper 1 in Oregon (100.5 megawatts) and Marengo (140.4 megawatts) in Washington. Leaning Juniper was acquired in November 2006, while Marengo is expected to come on line in 2007. The company also entered into a 20-year power purchase agreement for the total output at the Wolverine Creek plant in Idaho (64.5 megawatts).

PacifiCorp also has wind integration, storage and return agreements with Bonneville Power Administration, Eugene Water and Electric Board, Public Service Company of Colorado, and Seattle City Light. For the year ended December 31, 2006, electricity under these agreements totaled 552,835 megawatt-hours in addition to the wind energy generated or purchased for PacifiCorp's own use.

Geothermal
PacifiCorp owns and operates the Blundell Geothermal Plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 23 megawatts. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which will increase the output by 11 megawatts, is currently under construction and is expected to be in service by the end of 2007.

Biomass
Since the 2004 IRP, PacifiCorp has acquired power through power purchase agreements, as well as from several small biomass facilities under Qualifying Facility Agreements. Examples include the 20 megawatt Roseburg Lumber power purchase agreement and the 10 megawatt Freres Lumber power purchase agreement.

Solar
PacifiCorp has invested in Solar II, the world's largest solar energy plant, located in the Mojave Desert, and continues to assess the economic viability of such solar resources. At present, absent state-specific incentives, central-station solar resources continue to appear uneconomic when compared to other renewable resource alternatives. However, advances in solar technology can reasonably be expected to continue, and state-specific incentives may result in economic projects for consideration.

Regarding distributed photovoltaic (PV) applications, the company has installed panels of photovoltaic (PV) cells in its service area, including The High Desert Museum in Bend Oregon, PacifiCorp office in Moab, Utah, an elementary school in Green River, Wyoming, and has worked with Jackson County Fairgrounds and the Salt Palace in Salt Lake City, Utah on photovoltaic solar panels. Other locations in the service territory with solar include a 60 unit apartment in Salt Lake City, Utah and the North Wasco School district at Mosier, Oregon. Currently, there are 410 net meters throughout the company, mostly residential, and most have solar technology followed by wind and hydroelectric.

Hydroelectric Generation

PacifiCorp owns or purchases 1,556 megawatts of hydroelectric generation. These resources account for approximately 13 percent of PacifiCorp's total generating capability, in addition to providing operational benefits such as flexible generation, spinning reserves and voltage control. Hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate from its hydroelectric plants is dependent upon a number of factors, including the water content of snow pack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. When these conditions result in above average runoff, PacifiCorp is able to generate a higher than average amount of electricity using its hydroelectric plants. However, when these factors are unfavorable, PacifiCorp must rely to a greater degree on its more expensive thermal plants and the purchase of electricity to meet the demands of its customers.

PacifiCorp has added approximately 10 megawatts of additional capacity to its hydroelectric portfolio since the release of the 2004 IRP. This additional capacity is the result of turbine upgrades at its J.C. Boyle hydroelectric plant.

Demand-side Management

Demand-side management programs vary in their dispatchability, reliability of results, term of load reduction benefit and persistence over time. Each has its value and place in effectively managing utility investments, resource costs and system operations. Those that have greater persistence and firmness (can count on them to be delivered) can be relied upon as base resources for planning purposes; those that do not are well-suited as system reliability tools only. Reliability tools are used to avoid outages or high resource costs as a result of weather conditions, plant outages, market prices, and unanticipated system failures. These programs are divided into four general classes.

- **Class 1 DSM: Fully dispatchable or scheduled firm** – Class 1 programs are those for which capacity savings occur as a result of active company control or advanced scheduling. Once customers agree to participate in Class 1 DSM programs, the timing and persistence of the load reduction is involuntary on their part within the agreed limits and parameters of the program. In most cases, loads are shifted rather than avoided. Examples include residential and commercial central air conditioner load control programs ("Cool Keeper") that are dispatchable in nature and irrigation load management and interruptible or curtailment programs (scheduled firm).

- **Class 2 DSM: Non-dispatchable, firm energy efficiency programs** – Class 2 programs are those for which energy and capacity savings are achieved through facilitation of technological advancements in equipment, appliances, lighting and structures. These types of programs provide an incentive to customers to replace existing customer owned facilities (or to upgrade in new construction) to more efficient lighting, motors, air conditioners, insulation levels, windows, etc. Savings will endure over the life of the improvement (firm). Program examples include air conditioning efficiency programs ("Cool Cash"), comprehensive commercial and industrial new and retrofit energy efficiency programs ("Energy FinAnswer") and refrigerator recycling programs ("See ya later refrigerator").

- **Class 3 DSM: Price responsive programs** – Class 3 DSM programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or penalty. Savings are measured at a customer-by-customer level (via metering), and customers are compensated or charged in accordance with a program's pricing parameters. As a result of their voluntary nature, savings are less predictable, making them less suitable to incorporate into resource planning exercises, at least until such time that their size and customer behavior profile provide sufficient information to construct a diversity factor suitable for modeling purposes. Savings endure only for the duration of the incentive offering and loads tend to be shifted rather than avoided. Program examples include large customer energy bid programs ("Energy Exchange"), time-of-use pricing plans, critical peak pricing plans, and inverted tariff designs.

- **Class 4 DSM: Energy efficiency education and non-incentive based voluntary curtailment programs** – These programs represent energy and capacity reductions achieved through behavioral actions by customers in response to their desire to reduce their energy demands and costs, or voluntary compliance with a company request to conserve or shift their usage to off peak hours. Program savings are difficult to measure and aren't actively tracked in most cases. As a result, they can't be relied upon for planning purposes. The value of Class 4 DSM is longer-term in nature. Class 4 programs help foster an understanding and appreciation as to why utilities seek customer participation in Class 1-3 programs. Program examples include Utah's PowerForward program, company brochures with energy savings tips, customer news letters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs such as "Do the bright thing."

PacifiCorp has been operating successful DSM programs since the late 1980s. While the company's DSM focus has remained strong over this time, since the 2001 western energy crisis, the company's DSM pursuits have been expanded in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1-4) and resource planning considerations. Company investments have increased four times (from $50 million to $200 million) over the last five years (2002-2006) compared to the preceding five years (1997-2001) as the company has expanded DSM activity in the states of Utah, Washington and Idaho and transitioned existing DSM activities in Oregon over to the Energy Trust of Oregon.

The company is currently working with the state of Wyoming on a DSM application which seeks to expand company investments in Wyoming and which was filed in December 2006 and, is pending Commission approval by May 2007. Additionally, the company is working to expand DSM programs in California and is preparing a DSM application with expanded program offerings for filing with the California Public Utilities Commission in May 2007. In addition, the company has recently introduced new programs such as the Home Energy Savers program in Idaho, Washington, Utah and soon Wyoming and California, as well as expanding the Idaho irrigation load management program into Utah for the 2007 summer season. The following represents a brief summary of the existing resources by class. Appendix A provides a detailed list of existing DSM programs available and resource targets for Classes 1 through 3.

Class 1 Demand-side Management

There are currently three types of Class 1 programs in operation. Utah's "Cool Keeper" residential and small commercial air conditioner load control program provided nearly 80 megawatts of dispatchable load control (at the generator) during the summer of 2006 and is expected to deliver the anticipated 90 megawatts by summer 2007. Idaho's irrigation load management program achieved 55 megawatts of "scheduled" relief during the summer of 2006 and has recently added a "dispatchable" event option to compliment the "scheduled" options in an effort to increase that amount in 2007. As noted above, the company has expanded the "schedule" option to Utah beginning in 2007. First-year participation is expected to be modest; however, the company hopes to grow the program overtime to 15 megawatts. In addition to these two programs, the company has 233 megawatts of firm curtailable resources under contract with a select set of large industrial customers. Contracted curtailable loads are expected to increase to 308 megawatts by 2009.

Class 2 Demand-side Management
The cumulative historical energy and capacity savings (1992-2006) associated with Class 2 DSM resource acquisitions are over 300 average megawatts of energy and 390 megawatts respectively (at the generator). The company projects that through the 2016 planning period, existing Class 2 programs will yield, on average, an additional 23 MWa and 30 megawatts each year in energy and capacity reductions, respectively. The company is actively seeking new Class 2 programs and improvements to existing programs in an effort to nearly double this amount, provided those resources can be acquired cost-effectively.

Class 3 Demand-side Management
The company has numerous Class 3 programs currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), a seasonal inverted rate program (Utah), year-around inverted rate programs (Oregon, Washington and California) and Energy Exchange programs (Oregon, Utah and Washington). Savings associated with these programs are captured within the company's load forecast, with the exception of the Energy Exchange program. The impacts of these programs are thus captured in the integrated resource planning framework. Future savings associated with new programs, or added savings of existing programs, are relied upon as reliability resources as opposed to base resources. Current system-wide participation in metered time-of-day and time-of-use programs exceeds 23,000 customers, up from 15,000 in 2004. Approximately 1.25 million residential customers—89% of the company's residential customer base—are currently subject to inverted rate plans either seasonally or year-around.

PacifiCorp continues to evaluate Class 3 programs for applicability to long-term resource planning. As discussed in subsequent chapters, a variety of these programs were included as resource options in scenario modeling.

Class 4 Demand-side Management
Educating customers regarding energy efficiency and load management opportunities is an important component of the Company's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts, bill messages, newsletters, school education programs, and personal contact. Specific firm load reductions due to education will show up in other Class 4 DSM program results and changes in the load forecast over time.

Table 4.11 summarizes the existing DSM programs, and describes how they are accounted for as a planned resource.

Table 4.11 – Existing DSM Summary, 2007-2016

Program Class	Description	Energy Savings or Capacity at Generator	Included as Base Resources for 2007-2016 Period
1	Residential/small commercial air conditioner load control	100 MW summer peak	Yes
	Irrigation load management	55 MW summer peak	Yes
	Interruptible contracts	233 MW building to 308 MW	Yes

Program Class	Description	Energy Savings or Capacity at Generator	Included as Base Resources for 2007-2016 Period
		peak availability	
2	Company and Energy Trust of Oregon programs	227 MWa and 295 MW	No, captured as decrement to future load forecast
	Historic acquisitions towards 450 MWa (2004-2006 only)	95 MWa and 123 MW	No, accounted for in load forecasting
3	Energy Exchange	0-65 MW	No, leveraged as economic and reliability resource dependent on market prices/system loads
	Time-based pricing	MWa/MW unavailable 23,000 customers	No, historical behavior captured in load forecast
	Inverted rate pricing	MWa/MW unavailable 1.25 million residential	No, historical behavior captured in load forecast
4	PowerForward	0-78 MW summer peak	No, leveraged as economic and reliability resource dependent on market prices/system loads
	Energy Education	MWa/MW unavailable	No, captured in load forecast over time and other Class 1 and Class 2 program results

Contracts

PacifiCorp obtains the remainder of its energy requirements, including any changes from expectations, through long-term firm contracts, short-term firm contracts, and spot market purchases.

Listed below are the major contract expirations occurring within the next 10 years.

- The 202 megawatt West Valley lease expires in May 2008
- The 400 megawatt power purchase agreement with TransAlta Energy Marketing expires in June 2007
- The 575 megawatt BPA peaking contract expires in August 2011

Figure 4.1 presents the contract capacity in place for 2007 through 2016 as of April 2006. As shown, major capacity reductions in purchases and hydro contracts occur. (For planning purposes, PacifiCorp assumes that current Qualifying Facility and interruptible load contracts are extended to the end of the IRP study period.) Note that renewable wind contracts are shown at their capacity contribution levels.

Figure 4.1 – Contract Capacity in the 2007 Load and Resource Balance

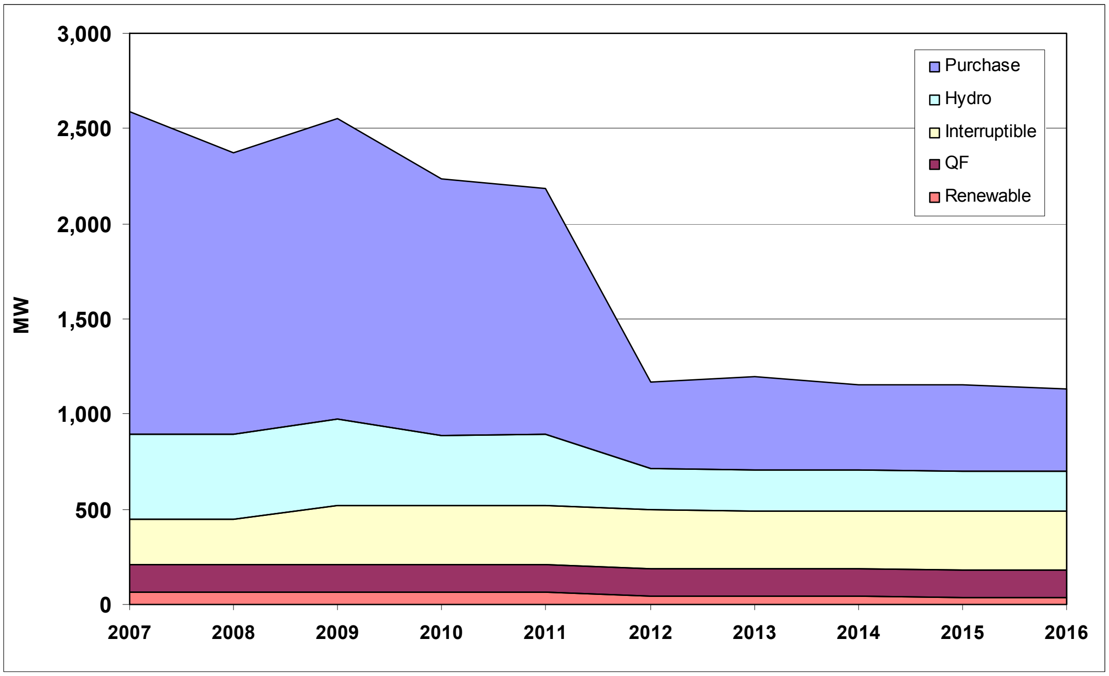
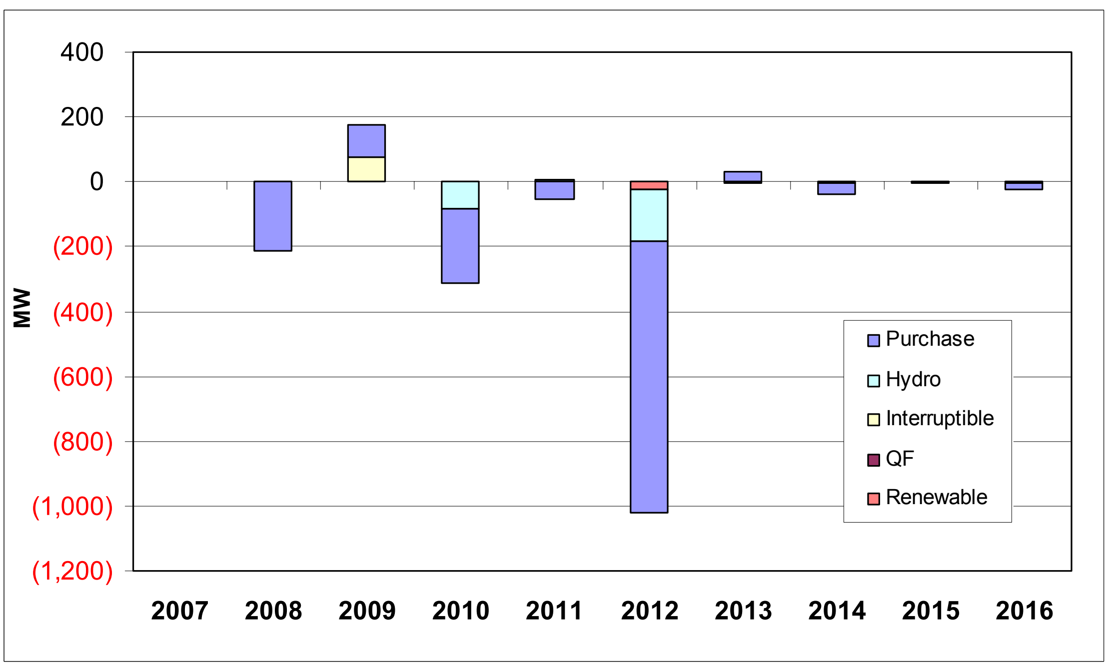


Figure 4.2 shows the year-to-year changes in contract capacity. Early year fluctuations are due to changes in short-term balancing contracts of one year or less, and expiration of the contracts cited above.

Figure 4.2 – Changes in Contract Capacity in the Load and Resource Balance



LOAD AND RESOURCE BALANCE

Capacity and Energy Balance Overview

The purpose of the load and resource balance is to compare the annual obligations for the first ten years of the study period with the annual capability of PacifiCorp's existing resources, absent new resource additions. This is done with respect to two views of the system, the capacity balance and energy balance.

The capacity balance compares generating capability to expected peak load at time of system peak load hours. It is a key part of the load and resource balance because it provides guidance as to the timing and severity of future resource deficits. It was developed by first determining the system coincident peak load hour for each of the first ten years (2007-2016) of the planning horizon. The peak load and the firm sales were added together for each of the annual system peak hours to compute the annual peak-hour obligation. Then the annual firm-capacity availability of the existing resources was determined for each of these annual system peak hours. The annual resource deficit (surplus) was then computed by multiplying the obligation by the planning reserve margin, and then subtracting the result from the existing resources.

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy over the first ten years of the planning horizon (2007-2016). The average obligation (load plus sales) was computed and subtracted from the average existing resource availability for each month and time-of-day period. This was done for each side of the PacifiCorp system as well as at the system level. The energy balance complements the capacity balance in that it also indicates when resource deficits occur, but it also provides insight into what type of resource will best fill the need. The usefulness of the energy balance is limited as it does not address the cost of the available energy. The economics of adding resources to the system are addressed with the studies and results of those studies described in Chapters 6 and 7 respectively.

Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculation. The main component categories consist of the following: existing resources, obligation, reserves, position, and reserve margin. This section provides a description of these various components.

Existing Resources

The firm capacities of the existing resources by resource category are summed to show the total available existing resource capacity for the east, west and for the PacifiCorp system. A description of each of the resource categories follows:

- **Thermal** – This includes all thermal plants that are wholly-owned or partially-owned by PacifiCorp. The capacity balance counts them at maximum dependable capability at time of system peak. The energy balance also counts them at maximum dependable capability, but derates them for forced outages and maintenance. This includes the existing fleet of 11 coal-fired plants, four natural gas-fired plants, and two co-generation units. These thermal resources account for roughly two-thirds of the firm capacity available in the PacifiCorp system.

- **Hydro** – This includes all hydroelectric generation resources operated in the PacifiCorp system as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at time of system peak. The energy associated with critical level stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. Over 90 percent of the hydroelectric capacity is situated on the west side of the PacifiCorp system.

- **Demand-side Management (DSM)** – There are about 160 megawatts of Class 1 demand-side management programs included as existing resources. Both the capacity balance and the energy balance count DSM programs by program capacity. DSM resources directly curtail load and thus planning reserves are not held for them.

- **Renewable** – This category contains two geothermal plants (the existing Blundell plant with the bottoming-cycle upgrade, and the Cove Fort project), eight existing wind projects and three planned wind projects from the MEHC commitments. The capacity balance counts the geothermal plants by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. Project-specific capacity credits for the wind resources were determined in a wind capacity planning contribution study (Appendix J). Wind energy is counted according to hourly generation data used to model the projects.

- **Purchase** – This includes all of the major contracts for purchases of firm capacity and energy in the PacifiCorp system. The capacity balance counts these by the maximum contract availability at time of system peak. The energy balance counts the optimum model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

- **Qualifying Facilities (QF)** – All Qualifying Facilities that provide capacity and energy are included in this category. Like other power purchases, the capacity balance counts them at maximum system peak availability and the energy balance counts them by optimum model dispatch. It is assumed that all Qualifying Facility agreements will stay in place for the entire duration of the 20-year planning period. It should be noted that three of the Qualifying Facility resources (Kennecott, Tesoro and US Magnesium) are considered non-firm and thus do not contribute to capacity planning.

- **Interruptible** – There are three east-side load curtailment contracts in this category. These agreements with Monsanto, MagCorp and Nucor provide about 300 megawatts of load interruption capability at time of system peak. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus planning reserves are not held for them.

Obligation
The obligation is the total electricity demand that PacifiCorp must serve consisting of forecasted retail load and firm contracted sales of energy and capacity. The following are descriptions of each of these components:

- **Load** – The largest component of the obligation is the retail loads of the load forecast. Described in the beginning of this chapter the load forecast is an hourly description of electric loads in the PacifiCorp system for the 20-year IRP study period (2007-2026). The capacity balance counts the load (MW) at the hour of system coincident peak load. The energy balance counts the load as an average of monthly time-of-day energy (MWa).

- **Sales** – This component includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system peak and the energy balance counts them by optimum model dispatch. All sales contracts are firm and thus planning reserves are held for them for the capacity balance. Note that for the 2007 IRP there was a reporting change for the delivery portion of exchange contracts. Exchange contract deliveries are no longer reported in the Purchase and Renewable components as was done for the 2004 IRP and 2004 IRP Update. These delivery amounts now appear in the Sales component.

Reserves
The reserves are the total megawatts of planning and non-owned reserves that must be held for this load and resource balance. A description of the two types of reserves follows:

- **Planning reserves** – This is the total reserves that must be held to provide the planning reserve margin.[28] It is the net firm obligation multiplied by the planning reserve margin as in the following equation:

  Planning reserves = (Obligation – Purchase – DSM – Interruptible) x PRM

- **Non-owned reserves** – There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. This amounts to an annual reserve obligation of about 7 megawatts and 71 megawatts on the west and east-sides, respectively.

Position
The position is the resource surplus (deficit) resulting from subtracting the existing resources from the obligation. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Reserve Margin
The reserve margin is the ratio of existing resources to the obligation. A positive reserve margin indicates that existing resources exceeds obligation. Conversely, a negative reserve margin indi-

[28] PacifiCorp models operating reserve requirements, which are based on minimum WECC Operating Reserves that cover Contingency Reserves and Regulating Reserves. PacifiCorp also includes incremental reserves for supporting wind, which is documented in Appendix J.

cates that existing resources do not meet obligation. If existing resources equals the obligation, then the reserve margin is zero percent. It should be pointed out that the reserve margin can be negative when the corresponding position is non-negative. This is because the reserve margin is measured relative to the obligation, while the position is measured relative to the obligation plus reserves.

Capacity Balance Determination

Methodology

The capacity balance is developed by first determining the system coincident peak load hour for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system peak hours and summed as follows:

Existing Resources = Thermal + Hydro + DSM + Renewable + Purchase + QF + Interruptible

The peak load and firm sales are then added together for each of the annual system peak hours to compute the annual peak-hour obligation:

Obligation = Load + Sales

The amount of reserves to be added to the obligation must then be calculated. This is done by first removing the firm purchase and load curtailment components of the existing resources from the obligation. This resulting net obligation is then multiplied by the planning reserve margin. The non-owned reserves are then added to this result to yield the megawatts of required reserves. The formula for this calculation is the following:

Reserves = (Obligation – Purchase – DSM – Interruptible) x PRM + Non-owned reserves

Finally, the annual capacity position is then computed by adding the computed reserves to the obligation and then subtracting the existing resources as in the following formula:

Capacity Position = Existing Resources – Obligation – Reserves

Load and Resource Balance Assumptions

The assumptions underlying the current load and resource balance are generally the same as those from the 2004 IRP Update with a few exceptions. The following is a summary of these assumption changes.

- **Front Office Transactions** – For the 2007 IRP, front office transactions were taken out of the existing load and resource balance in order to treat them as potential resources that the Capacity Expansion Module can pick from. This was done in order to treat the front office transactions on a comparable basis to other supply-side resources.

- **Wind Commitment** – In the 2004 IRP Update, 1,400 megawatts of wind were included as planned resources in the initial load and resource balance. For the 2007 IRP, 400 megawatts of the overall 1,400-megawatt commitment are included in the initial load and resource balance. The remaining 1,000 megawatts are treated as part of the overall wind resource potential evaluated in portfolio modeling.

- **Clark County Load Service Contract** – In the 2004 IRP Update, the Clark County load service contract including the River Road combined-cycle gas resource was modeled. This contract ends in 2007 and affects little of the 20-year planning horizon. Also, the energy from the component resources and load obligation balances out. Thus, this contract is not part of this load and resource balance.

- **Planning Reserve Calculation for Firm Transactions and Load Curtailment Contracts** – In the 2007 IRP, the company represents front office transactions as firm purchases. Consistent with current market practices, the seller, rather than the company as the purchaser, carries the operating reserve obligation.[29] Load curtailment contracts and DSM programs directly reduce firm load. Thus, the planning reserve margin is not applied to firm purchases, DSM programs and interruptible resources. This was not done in the 2004 IRP Update.

- **Non-owned Reserves** – The 2007 IRP includes the modeling of capacity obligation resulting from the holding of reserves for counterparties within the PacifiCorp control areas. This was not done in the 2004 IRP Update.

- **Planning Reserve Margin** – The planning reserve margin is the generating capability that exceeds the expected peak load for each year. The 2004 IRP and 2004 IRP Update assumed a 15 percent planning reserve margin. However, the 2007 IRP considers resource portfolios at 12 and 15 percent levels. PacifiCorp views this percentage range as a prudent and reasonable range for planning purposes when considering both supply reliability and economic impact to customers.[30]

Capacity Balance Results

Table 4.12 shows the annual capacity balances and component line items using a planning reserve margin of 12 percent to calculate the planning reserve amount. Balances for the system as well as PacifiCorp's east and west control areas are shown. (It should be emphasized that while west and east balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.) For comparison purposes, Table 4.13 shows the system-level capacity balance assuming a 15 percent planning reserve margin.

Figures 4.3 through 4.5 display the annual capacity positions (resource surplus or deficits) for the system, west control area, and east control area, respectively. The associated obligation with both 12 and 15 percent planning reserve margins are shown. The decrease in resources in 2008 is caused by the expected expiration of the West Valley lease agreement. The slight increase in

[29] Recently, there have been proposals made to the Western Electricity Coordinating Council board of directors to change the current market practice that would require the operating reserve obligation to be calculated based on the load serving entity's load, and the obligation would be independent of purchases or sales. If this change is adopted, the company will need to modify its assumptions in future integrated resource plans to calculate the operating reserve obligation based on its load.

[30] To provide context, note that the IRP Benchmarking Study in Appendix C of the 2004 IRP Update identified numerous planning reserve margins used by utilities that range from 11 to 20 percent. Also, the Pacific Northwest Resource Adequacy Forum recently developed a regional pilot capacity adequacy standard that included a 19 percent planning reserve margin for summer peak planning for the Pacific Northwest.

2009 is due to executed front office transactions and an increase in the curtailment portion of the Monsanto contract. The large decrease in 2012 is primarily due to the expiration of the BPA peaking contract in August 2011. Additionally, Figure 4.4 highlights a decrease in obligation in the west starting in 2014. This is due to the expiration of the Sacramento Municipal Utility District and City of Redding power sales contracts.

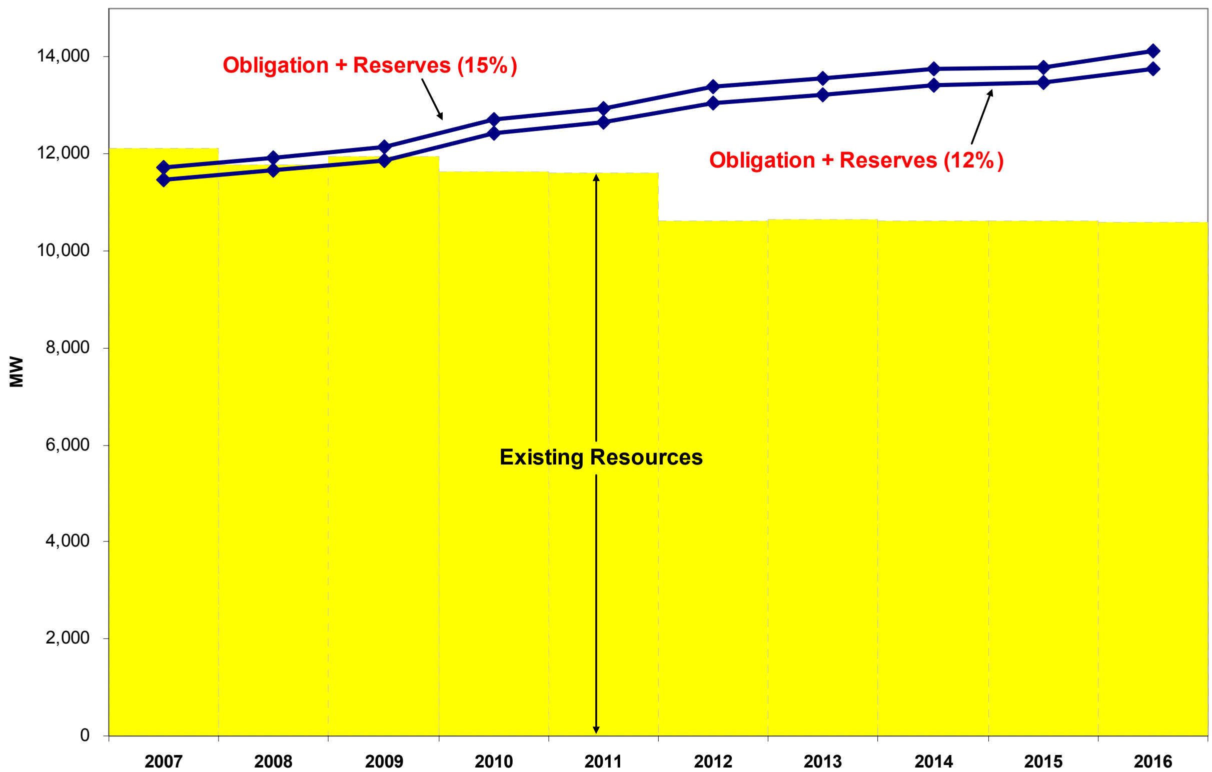
Table 4.12 – Capacity Load and Resource Balance (12% Planning Reserve Margin)

Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
East										
Thermal	6,134	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	153	163	163	163	163	163	163	163	163	163
Renewable	65	109	109	109	109	109	109	109	105	105
Purchase	904	679	778	548	543	343	343	343	343	322
QF	106	106	106	106	106	106	106	106	106	106
Interruptible	233	233	308	308	308	308	308	308	308	308
East Existing Resources	7,730	7,366	7,540	7,310	7,305	7,105	7,105	7,105	7,101	7,080
Load	6,321	6,515	6,657	7,137	7,289	7,595	7,738	7,895	8,026	8,366
Sale	849	811	702	666	631	595	595	595	595	595
East Obligation	7,170	7,326	7,359	7,803	7,920	8,190	8,333	8,490	8,621	8,961
Planning reserves	706	750	733	814	829	885	902	921	937	980
Non-owned reserves	71	71	71	71	71	71	71	71	71	71
East Reserves	776	821	804	885	899	956	973	992	1,007	1,051
East Obligation + Reserves	7,946	8,147	8,163	8,688	8,819	9,146	9,306	9,482	9,628	10,012
East Position	(217)	(781)	(623)	(1,378)	(1,514)	(2,041)	(2,201)	(2,377)	(2,528)	(2,932)
East Reserve Margin	9%	1%	4%	-6%	-7%	-13%	-14%	-16%	-17%	-21%
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,421	1,414	1,328	1,357	1,225	1,249	1,243	1,244	1,242
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	108	108	108	108	108	84	84	84	84	84
Purchase	786	800	800	799	749	112	141	107	107	107
QF	40	40	40	40	40	40	38	38	38	38
West Existing Resources	4,401	4,415	4,408	4,321	4,300	3,506	3,558	3,519	3,519	3,518
Load	2,922	2,924	3,095	3,124	3,199	3,240	3,251	3,262	3,271	3,252
Sale	299	299	299	290	290	258	258	258	158	108
West Obligation	3,221	3,223	3,394	3,414	3,489	3,498	3,509	3,520	3,429	3,360
Planning reserves	292	291	311	314	329	406	404	409	399	390
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	299	297	318	320	335	413	411	416	405	397
West Obligation + Reserves	3,520	3,520	3,712	3,734	3,824	3,911	3,920	3,936	3,834	3,757
West Position	881	895	696	587	476	(405)	(362)	(417)	(314)	(239)
West Reserve Margin	39%	40%	33%	29%	26%	0%	2%	0%	3%	5%
System										
Total Resources	12,131	11,780	11,948	11,631	11,605	10,611	10,663	10,624	10,620	10,598
Obligation	10,391	10,549	10,753	11,217	11,409	11,688	11,842	12,010	12,050	12,321
Reserves	1,075	1,118	1,122	1,205	1,234	1,369	1,384	1,408	1,412	1,447
Obligation + Reserves	11,466	11,667	11,874	12,421	12,643	13,057	13,226	13,417	13,462	13,768
System Position	665	113	73	(791)	(1,038)	(2,446)	(2,563)	(2,794)	(2,842)	(3,171)
Reserve Margin	18%	13%	13%	5%	3%	-9%	-10%	-11%	-12%	-14%

Table 4.13 – System Capacity Load and Resource (15% Planning Reserve Margin)

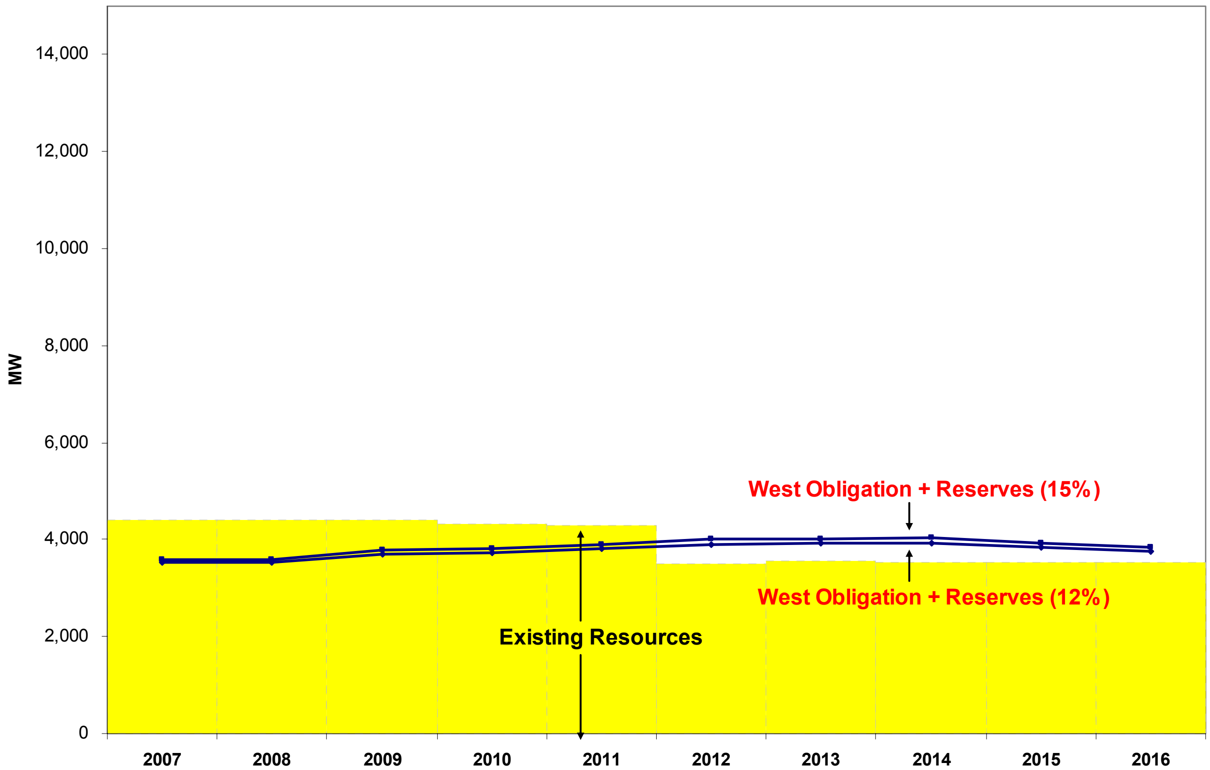
Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
System										
Total Resources	12,131	11,780	11,948	11,631	11,605	10,611	10,663	10,624	10,620	10,598
Obligation	10,391	10,549	10,753	11,217	11,409	11,688	11,842	12,010	12,050	12,321
Reserves	1,324	1,378	1,383	1,487	1,524	1,691	1,710	1,740	1,746	1,790
Obligation + Reserves	11,715	11,927	12,136	12,703	12,932	13,380	13,552	13,750	13,796	14,111
System Position	415	(147)	(188)	(1,073)	(1,327)	(2,768)	(2,890)	(3,126)	(3,176)	(3,513)
Reserve Margin	19%	14%	13%	5%	3%	-9%	-9%	-11%	-11%	-14%

Figure 4.3 – System Coincident Peak Capacity Chart



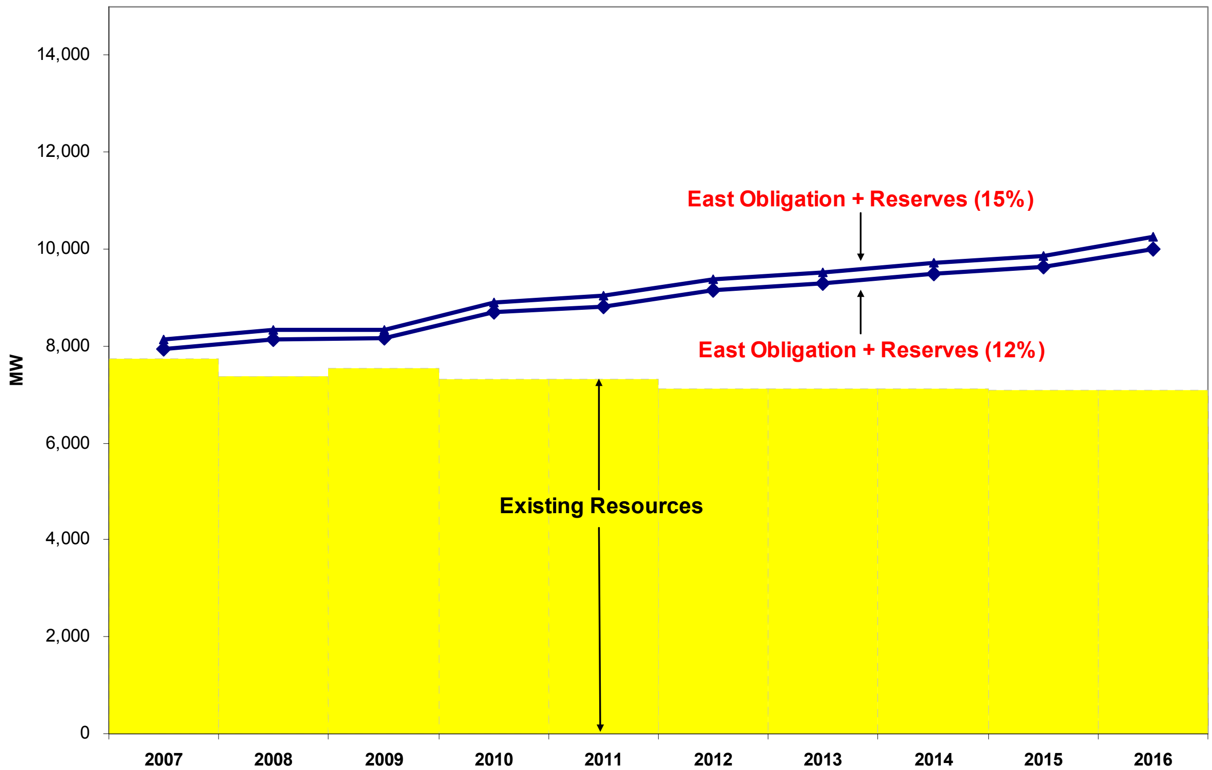
Resources	12,131	11,780	11,948	11,631	11,605	10,611	10,663	10,624	10,620	10,598
Obligation +Reserves 12% PRM	11,466	11,667	11,874	12,421	12,643	13,057	13,226	13,417	13,462	13,768
Obligation +Reserves 15% PRM	11,715	11,927	12,136	12,703	12,932	13,380	13,552	13,750	13,796	14,111
12% System Position	665	113	73	(791)	(1,038)	(2,446)	(2,563)	(2,794)	(2,842)	(3,171)
15% System Position	415	(147)	(188)	(1,073)	(1,327)	(2,768)	(2,890)	(3,126)	(3,176)	(3,513)

Figure 4.4 – West Coincident Peak Capacity Chart



Resources	4,401	4,415	4,408	4,321	4,300	3,506	3,558	3,519	3,519	3,518
Obligation + Reserves 12% PRM	3,520	3,520	3,712	3,734	3,824	3,911	3,920	3,936	3,834	3,757
Obligation +Reserves 15% PRM	3,593	3,593	3,789	3,812	3,906	4,013	4,021	4,038	3,933	3,854
12% PRM Position	881	895	696	587	476	(405)	(362)	(417)	(314)	(239)
15% PRM Position	808	822	618	509	394	(506)	(463)	(519)	(414)	(336)

Figure 4.5 – East Coincident Peak Capacity Chart



Resources	7,730	7,366	7,540	7,310	7,305	7,105	7,105	7,105	7,101	7,080
Obligation + Reserves 12% PRM	7,946	8,147	8,163	8,688	8,819	9,146	9,306	9,482	9,628	10,012
Obligation + Reserves 15% PRM	8,123	8,334	8,346	8,891	9,027	9,367	9,531	9,712	9,863	10,257
12% PRM Position	(217)	(781)	(623)	(1,378)	(1,514)	(2,041)	(2,201)	(2,377)	(2,528)	(2,932)
15% PRM Position	(393)	(969)	(806)	(1,581)	(1,722)	(2,262)	(2,427)	(2,607)	(2,762)	(3,177)

Energy Balance Determination

Methodology

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy. The on-peak hours are weekdays and Saturdays from hour-ending 7:00 am to 10:00 pm; off-peak hours are all other hours. The existing resource availability is computed for each month and daily time block without regard to economic considerations. Peaking resources such as the Gadsby units are counted only for the on-peak hours. This is calculated using the formulas that follow. Please refer to the section on load and resource balance components for details on how energy for each component is counted.

Existing Resources = Thermal + Hydro + DSM + Renewable + Purchase + QF + Interruptible

The average obligation is computed using the following formula:

Obligation = Load + Sales

The energy position by month and daily time block is then computed as follows:

Energy Position = Existing Resources – Obligation – Reserve Requirements (12% PRM)

Energy Balance Results

Figures 4.6 through 4.8 show the energy balances for the system, west control area, and east control area, respectively. They show the energy balance on a monthly average basis across all hours, and also indicate the average annual energy position. The cross-over point, where the system becomes energy deficient on an average annual basis, is 2009, absent any economic considerations.

Figure 4.6 – Average Monthly and Annual System Energy Balances

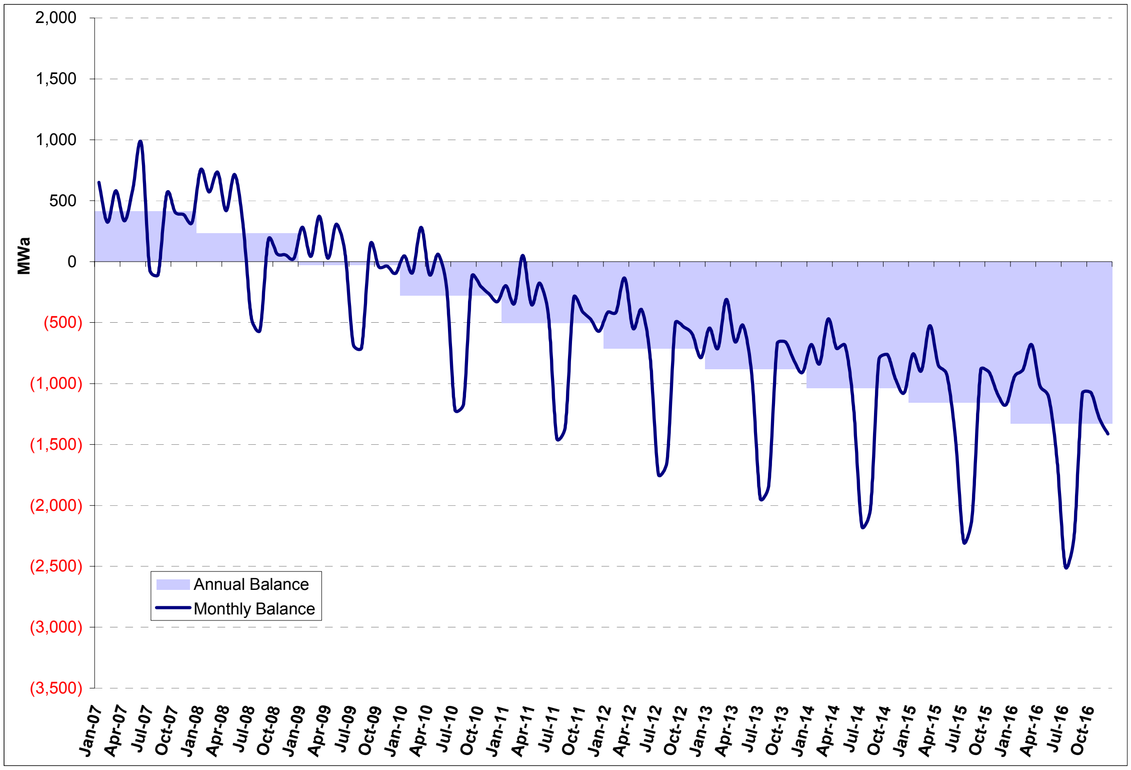


Figure 4.7 – Average Monthly and Annual West Energy Balances

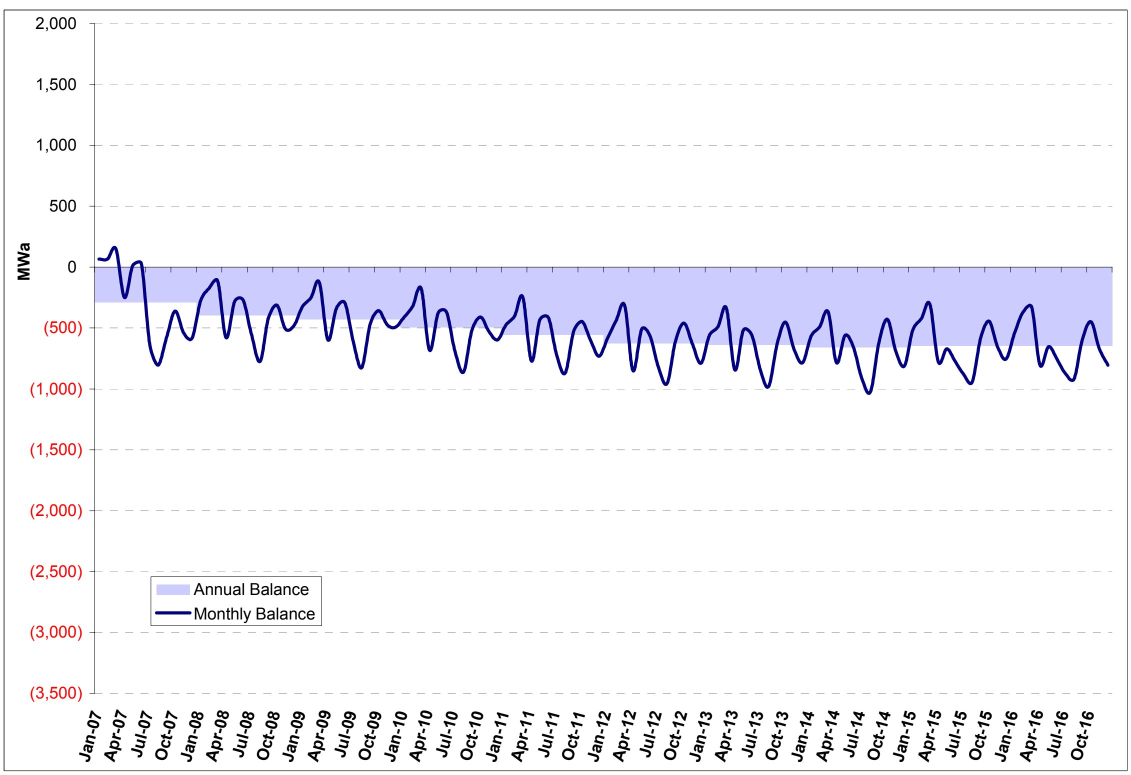
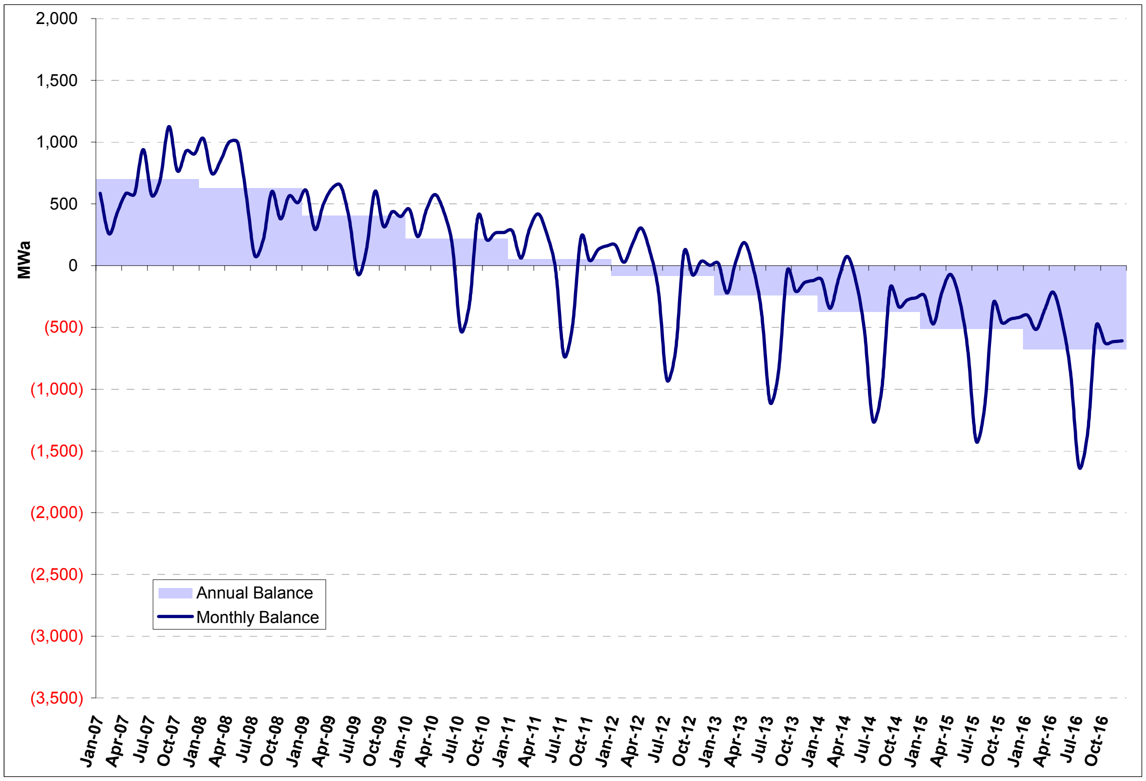


Figure 4.8 – Average Monthly and Annual East Energy Balances



Load and Resource Balance Conclusions

The company projects a summer peak resource deficit for the PacifiCorp system beginning in 2008 to 2010, depending on the planning reserve margin assumed. The PacifiCorp deficits prior to 2011 to 2012 will be met by additional renewables, demand side programs, and market purchases. The company will consider other options during this time frame if they are cost-effective and provide other system benefits. This could include acceleration of a natural gas plant to complement the accelerated and expanded acquisition of renewable wind facilities. Then beginning in 2011 to 2012, base load, intermediate load, or both types of resource additions will be necessary to cover the widening capacity and annual energy deficits. The capacity balance at a 12 percent planning reserve margin indicates the start of a deficit beginning in 2010—the system is short by 791 megawatts. This capacity deficit increases to 2,400 megawatts in 2012 and then to almost 3,200 megawatts in 2016. On an annual basis, and disregarding economic considerations, the company becomes deficit with respect to energy by 2009.

5. RESOURCE OPTIONS

Chapter Highlights

- For use in portfolio modeling, PacifiCorp developed cost and performance profiles for supply-side resources, demand-side management programs, transmission expansion projects, and market purchases (front office transactions).

- PacifiCorp used the Electric Power Research Institute's Technical Assessment Guide (TAG®), along with recent project experience and consultant studies, to develop its supply-side resource options. The use of TAG information is new to PacifiCorp's integrated resource planning process.

- Also new to the company's integrated planning process is the estimation and use of capital cost ranges for each supply-side option. These cost ranges reflect cost uncertainty, and their use in this plan acknowledges the significant construction cost increases taking place.

- The company commissioned Quantec LLC to construct proxy supply curves for Class 1 (fully dispatchable or scheduled firm) and Class 3 (price-responsive) demand-side management programs.

- The company developed transmission resources to support new generation options, to enhance transfer capability and reliability across PacifiCorp's system, and to boost import/export capability with respect to external markets. These transmission resources were entered as options in PacifiCorp's capacity expansion optimization tool, and were thus allowed to compete directly with other resources for inclusion in portfolios.

INTRODUCTION

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of supply-side generation, demand-side management programs, transmission expansion projects, and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures. The chapter concludes with a discussion on the use and impact of physical and financial hedging strategies.

SUPPLY-SIDE RESOURCES

Resource Selection Criteria

The list of supply-side resource options has been reduced in relation to previous IRP resource lists to reflect the realities evidenced through previous studies and to help efficiently manage the computer processing time involved in developing detailed portfolios. For instance, subcritical pulverized coal resources are not included since it is felt than any new, large (greater than 500 megawatts) pulverized coal plant will utilize a supercritical boiler based on the increased efficiency and superior environmental performance of the supercritical designs. Similarly, natural gas based options based on smaller, less efficient combustion turbines have not been included since previous IRP exercises have demonstrated that the superior heat rate and cost performance of larger combustion turbines will cause the larger machines to be selected over the smaller options.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major electrical generating resources from the 2004 IRP Update. This resource list was reviewed and, in some cases, simplified. Once the basic list of resources was determined the cost and performance attributes for each resource was estimated. A number of information sources were used to identify parameters needed to model these resources. PacifiCorp has conducted a number of engineering studies to understand the cost of coal and gas resources in recent years. Recent experience with the construction of the 2x1 combined cycle plants at Currant Creek and Lake Side as well as other recent simple cycle projects at Gadsby and West Valley has provided PacifiCorp with insight into the current cost of new power generating facilities. For newer technologies (integrated gasification combined cycle (IGCC) plants and supercritical pulverized coal plants) a study performed by WorleyParsons was used along with internal studies to review the cost estimates of these resources.

In order to refresh the modeling data used in the 2004 IRP Update, PacifiCorp purchased a license to utilize the Electric Power Research Institute (EPRI) new resource data base called the Technical Assessment Guide® (TAG). The TAG contains information on capital cost, heat rate, availability, and fixed and variable operating and maintenance cost estimates. The data in the TAG must be customized for each application by adjusting basic financial parameters as well as physical parameters for each potential site, such as coal quality, water availability, and elevation.

The 2006 TAG data were used to develop a cost and performance profile for each potential resource. The results of the TAG runs were compared to the actual cost data from recent projects as well as internal PacifiCorp studies of site specific generation options. The TAG results were customized to give results approximately in agreement to these recent studies. The customization was primarily done for capital costs, and reflects market conditions as of late spring of 2006. Of particular concern with the capital costs contained in the TAG database was the apparent lag in the TAG results in recognizing the recent trend of increases in capital costs for power generating equipment. It was apparent from numerous discussions with engineering and construction companies in the power industry that construction costs have increased substantially in the last two to three years. These increases, on the order of 25 to 35 percent with respect to the costs reported in the 2004 IRP Update, are due to increased construction activity stemming from shortages of equipment, material, and skilled construction labor. The TAG numbers, in general, did not address this recent capital cost trend. The TAG methodology does allow for customization to account for this increase. Therefore, costs were adjusted in the TAG to be consistent with other studies. Heat rate, availability, and operating and maintenance costs were, in general, calculated by the TAG.

TAG runs were created for all technologies in the supply-side resource table except as noted below for combined heat and power plants.

Handling of Technology Improvement Trends and Cost Uncertainty

As mentioned above, the capital cost uncertainty for many of the proposed projects is increasing. Additionally, some technologies, such as IGCC, have a greater uncertainty because only a few demonstration units have been built and operated. A range of estimated capital costs is displayed in the supply-side resource options table. This range of capital cost was adjusted by factors reflecting the potential cost of various technologies as compared to a combined cycle natural gas plant. The combined cycle natural gas plant is the easiest technology to predict capital costs for since there is less field labor and PacifiCorp has recent (Currant Creek) and on-going (Lake Side) experience with this kind of project.

The cost factors used to reflect technology risk in the uncertainty range for various resource options were taken from a U.S Energy Information Administration paper "Assumptions to the Annual Energy Outlook 2006, DOE/EIA-0554(2006), March 2006". In addition to the technology factors the TAG capital cost estimates were adjusted by 5 percent on the low end and 10 percent on the high end to give an overall range.

There is a potential for future relative cost decreases for certain technologies such as IGCC. As the technology matures and more plants are built and operated the costs of such new technologies may decrease relative to more mature options such as pulverized coal. The supply-side options table does not consider the potential for such savings since the benefits are not expected to be realized until the next generation of new plants are built and operated for a period of time. Any such benefits are not expected to be available until after 2020 and future IRPs will be able to incorporate the benefit of such future cost reductions.

Resource Options and Associated Attributes

Tables 5.1 and 5.2 present cost and performance attributes for supply-side resource options designated for PacifiCorp's east and west control areas, respectively. Tables 5.3 and 5.4 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2006 dollars. Options included in PacifiCorp's IRP models are highlighted. As mentioned above, the attributes were mainly derived from the EPRI TAG database with certain technologies adjusted to be more in line with PacifiCorp's recent cost studies and project experience. Cost and performance values reflect analysis concluded by July 2006. Additional explanatory notes for the tables are as follows:

- The second 600-megawatt Utah supercritical pulverized coal resource is modeled as a 340-megawatt share to emulate the Intermountain Power Project acquisition opportunity.

- Capital costs are intended to be all-inclusive, and account for Allowance for Funds Used During Construction (AFUDC), land, EPC (Engineering, Procurement, and Construction) cost premiums, owner's costs, etc. Capital costs in Tables 5.1 and 5.2 reflect mid-2006 current dollars, and do not include escalation from the current year to the year of commercial operation.
- Wind sites are modeled with differing peak load carrying capability levels. These levels are reported for each wind site in the Wind Capacity Planning Contribution section of Appendix J.
- For customer-owned standby generators, the 40 megawatts of capacity is the assumed aggregate availability of dispatchable megawatts rather than an average capacity per plant. The capital cost listed includes interconnection and emission control upgrade costs. The variable operations and maintenance (O&M) cost reflects the cost of #2 fuel oil, which is based on an average forecasted monthly fuel price of $13.9/MMBtu for the 2007 to 2026 period.
- Certain resource names are listed as acronyms. These include:
  PC – pulverized coal
  IGCC – integrated gasification combined cycle
  SCCT – simple cycle combustion turbine
  CCCT – combined cycle combustion turbine
  CHP – combined heat and power (cogeneration)
- For the CHP resources, a steam credit is applied against the variable O&M cost, or, in the case of the west-side topping cycle combustion turbine, against the heat rate.
- The costs presented do not include any investment tax credits.
- The heat rate for the solar trough resource with CCCT backup (11,750 Btu/kWh) reflects gas operation only, and comes directly from the EPRI TAG database. Gas backup for solar is less efficient than for a standalone CCCT.
- For the nuclear option, costs do not include fuel disposal.
- The capital cost columns in Tables 5.3 and 5.4 reports averages of the low and high capital cost estimates presented in Tables 5.1 and 5.2.

Table 5.1 – East Side Supply-Side Resource Options
(2006 Dollars)

Description	Location/Timing: Installation Location	Location/Timing: Earliest In-Service Date (Mid-Year)	Plant Details: Average Capacity (MW)	Plant Details: Design Plant Life in Years	Plant Details: Ave. Annual Heat Rate (Btu/kWh)	Outage Information: Maint. Outage Rate	Outage Information: Equivalent Forced Outage Rate (EFOR)	Costs: Low Estimate Capital Cost ($/kW)	Costs: High Estimate Capital Cost ($/kW)	Costs: Var. O&M ($/MWh)	Costs: Fixed O&M ($/kW-yr)	Emissions: SO2 lbs/MMBTU	Emissions: NOx lbs/MMBTU	Emissions: Hg lbs/Tbtu	Emissions: CO_2 lbs/MMBTU
East Side Options (4500')															
Coal															
Utah PC Supercritical 1 (600 MW)	Utah	2012	600	40	9,169	5%	4%	$ 1,940	$ 2,266	$ 2.41	$ 35.65	0.062	0.070	0.600	205.35
Utah PC Supercritical 2 (600 MW)	Utah	2012	600	40	9,169	5%	4%	$ 1,940	$ 2,266	$ 2.41	$ 35.65	0.062	0.070	0.600	205.35
Utah IGCC (Min. Carbon Prep/Level II Controls)	Utah	2014	508	40	8,732	5%	6%	$ 2,269	$ 2,690	$ 1.10	$ 81.31	0.014	0.014	0.300	205.35
Utah IGCC (Min. Carbon Prep/Level II - no spare gas.)	Utah	2014	508	40	8,732	10%	11%	$ 2,141	$ 2,538	$ 1.10	$ 76.71	0.014	0.014	0.300	205.35
Utah IGCC with Carbon Capture & Sequestration	Utah	2014	470	40	9,917	5%	6%	$ 2,901	$ 3,439	$ 6.28	$ 114.50	0.014	0.014	0.300	20.54
Wyoming PC Supercritical (750 MW)	Wyoming	2014	750	40	9,427	5%	4%	$ 1,930	$ 2,256	$ 2.08	$ 41.06	0.062	0.070	0.600	205.35
Wyoming IGCC (Min. Carbon Prep/Level II Controls)	Wyoming	2014	497	40	8,915	5%	6%	$ 2,471	$ 2,929	$ 1.08	$ 81.32	0.013	0.013	0.300	205.35
Natural Gas															
Microturbine	Utah	2007	0.03	15	12,885	1%	1%	$ 929	$ 1,076	$ 2.00	$ 200.00	0.001	0.101	0.255	118.00
Small Non-CT CHP	Utah	2009	25	25	5,156	5%	10%	$ 824	$ 945	$ 0.20	$ 29.49	0.001	0.080	0.255	118.00
Small Industrial CHP	Utah	2008	4	25	12,590	7%	2%	$ 1,454	$ 1,669	$ (0.32)	$ 8.22	0.001	0.138	0.255	118.00
Small Commercial CHP	Utah	2008	1	25	10,035	3%	1%	$ 1,167	$ 1,339	$ (0.03)	$ 1.35	0.001	0.220	0.255	118.00
Fuel Cell - Small (Solid Oxide)	Utah	2008	0.3	25	7,820	1%	2%	$ 1,577	$ 1,913	$ 0.03	$ 9.70	0.001	0.003	0.255	118.00
Fuel Cell - Large (Solid Oxide)	Utah	2012	25	25	6,250	2%	3%	$ 1,117	$ 1,355	$ 0.03	$ 8.40	0.001	0.003	0.255	118.00
SCCT Aero	Utah	2009	79	25	10,744	7%	10%	$ 701	$ 804	$ 7.08	$ 20.91	0.001	0.011	0.255	118.00
Intercooled Aero SCCT	Utah	2009	78	25	9,436	3%	2%	$ 698	$ 801	$ 2.58	$ 29.02	0.001	0.011	0.255	118.00
Internal Combustion Engines	Utah	2009	153	25	8,390	5%	1%	$ 824	$ 946	$ 5.20	$ 12.80	0.001	0.017	0.255	118.00
SCCT Frame (2 Frame "F")	Utah	2009	302	35	11,509	7%	10%	$ 465	$ 534	$ 10.86	$ 5.78	0.001	0.050	0.255	118.00
CCCT (Wet "F" 1x1)	Utah	2010	222	35	7,223	7%	5%	$ 834	$ 957	$ 2.60	$ 16.42	0.001	0.011	0.255	118.00
CCCT Duct Firing (Wet "F" 1x1)	Utah	2010	50	35	8,868	7%	5%	$ 277	$ 318	$ 0.11	$ -	0.001	0.011	0.255	118.00
CCCT (Wet "F" 2x1)	Utah	2010	448	35	7,164	7%	5%	$ 759	$ 870	$ 2.60	$ 9.98	0.001	0.011	0.255	118.00
CCCT Duct Firing (Wet "F" 2x1)	Utah	2010	100	35	8,868	7%	5%	$ 255	$ 292	$ 0.11	$ -	0.001	0.011	0.255	118.00
CCCT (Wet "G" 1x1)	Utah	2010	297	35	7,075	7%	5%	$ 789	$ 905	$ 2.55	$ 12.42	0.001	0.011	0.255	118.00
CCCT Duct Firing (Wet "G" 1x1)	Utah	2010	60	35	8,868	7%	5%	$ 292	$ 335	$ 0.11	$ -	0.001	0.011	0.255	118.00
Other - Renewables															
SW Wyoming Wind	Wyoming	2008	50	20	n/a	n/a	n/a	$ 1,556	$ 1,919	$ -	$ 29.78	-	-	-	-
Idaho Wind	Utah	2008	50	20	n/a	n/a	n/a	$ 1,556	$ 1,919	$ -	$ 29.78	-	-	-	-
Geothermal, Dual Flash	Utah	2009	35	35	n/a	3%	1%	$ 3,101	$ 3,591	$ 5.50	$ 22.60	-	-	-	-
Battery Storage	Utah	2009	20	30	12,000	2%	5%	$ 1,298	$ 1,503	$ 10.00	$ 1.00	0.100	0.400	3.000	205.35
Pumped Storage	Nevada	2017	350	50	13,000	5%	5%	$ 1,104	$ 1,278	$ 4.30	$ 4.30	0.100	0.400	3.000	205.35
Compressed Air Energy Storage (CAES)	Wyoming	2010	350	25	11,670	7%	10%	$ 698	$ 808	$ 5.50	$ 3.80	0.001	0.011	0.255	118.00
Nuclear, Passive Safety	Utah	2022	600	40	10,710	7%	8%	$ 2,382	$ 2,889	$ 0.38	$ 109.72	-	-	-	-
Solar Thermal Trough with Natural Gas Backup	Utah	2010	200	30	11,750	n/a	n/a	$ 3,541	$ 4,337	$ 3.10	$ 26.10	-	-	-	-

Table 5.2 – West Side Supply-Side Resource Options
(2006 Dollars)

	Location/Timing		Plant Details			Outage Information		Costs				Emissions			
Description	Installation Location	Earliest In-Service Date (Mid-Year)	Average Capacity (MW)	Design Plant Life in Years	Ave. Annual Heat Rate (Btu/kWh)	Maint. Outage Rate	Equivalent Forced Outage Rate (EFOR)	Low Estimate Capital Cost ($/kW)	High Estimate Capital Cost ($/kW)	Var. O&M ($/MWh)	Fixed O&M ($/kW-yr)	SO2 lbs/MMBTU	NOx lbs/MMBTU	Hg lbs/Tbtu	CO_2 lbs/MMBTU
West Side Options (1500')															
Natural Gas															
Microturbine	Northwest	2007	0.03	15	12,885	1%	1%	$ 845	$ 978	$ 1.82	$ 181.82	0.001	0.101	0.255	118.00
Fuel Cell - Small (Solid Oxide)	Northwest	2008	0.225	25	7,820	1%	2%	$ 1,433	$ 1,739	$ 0.03	$ 8.82	0.001	0.003	0.255	118.00
SCCT Aero	Northwest	2009	87	25	10,744	7%	10%	$ 637	$ 731	$ 6.44	$ 19.01	0.001	0.011	0.255	118.00
Intercooled Aero SCCT	Northwest	2009	86	25	9,436	3%	2%	$ 635	$ 728	$ 2.35	$ 26.38	0.001	0.011	0.255	118.00
Internal Combustion Engines	Northwest	2009	168	25	8,390	5%	1%	$ 749	$ 860	$ 5.20	$ 12.80	0.001	0.017	0.255	118.00
SCCT Frame (2 Frame "F")	Northwest	2009	332	35	11,509	7%	10%	$ 423	$ 485	$ 9.87	$ 5.25	0.001	0.050	0.255	118.00
CCCT (Wet "F" 1x1)	Northwest	2010	244	35	7,223	7%	5%	$ 758	$ 870	$ 2.36	$ 14.93	0.001	0.011	0.255	118.00
CCCT Duct Firing (Wet "F" 1x1)	Northwest	2010	55	35	8,868	7%	5%	$ 252	$ 289	$ 0.10	$ -	0.001	0.011	0.255	118.00
CCCT (Wet "F" 2x1)	Northwest	2010	492	35	7,164	7%	5%	$ 690	$ 791	$ 2.36	$ 9.07	0.001	0.011	0.255	118.00
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2010	110	35	8,868	7%	5%	$ 232	$ 266	$ 0.10	$ -	0.001	0.011	0.255	118.00
CCCT (Wet "G" 1x1)	Northwest	2010	326	35	7,075	7%	5%	$ 717	$ 822	$ 2.32	$ 11.29	0.001	0.011	0.255	118.00
CCCT Duct Firing (Wet "G" 1x1)	Northwest	2010	66	35	8,868	7%	5%	$ 266	$ 305	$ 0.10	$ -	0.001	0.011	0.255	118.00
Other - Renewables															
Oregon Wind	Northwest	2008	50	20	n/a	n/a	5%	$ 1,556	$ 1,919	$ -	$ 29.78	-	-	-	-
Geothermal, Dual Flash	Northwest	2009	35	35	n/a	3%	1%	$ 3,101	$ 3,591	$ 5.50	$ 22.60	-	-	-	-
Compressed Air Energy Storage (CAES)	Northwest	2010	385	25	11,670	7%	10%	$ 635	$ 735	$ 5.00	$ 3.45	0.001	0.011	0.255	118.00
West Side Options (Sea Level)															
Coal															
Washington IGCC (Min. Carbon Prep/Level II Controls)	Northwest	2014	600	40	8,732	5%	6%	$ 2,269	$ 2,690	$ 1.10	$ 81.31	0.014	0.014	0.300	205.35
Natural Gas															
Microturbine	Northwest	2007	0.03	15	12,885	1%	1%	$ 803	$ 929	$ 1.73	$ 172.73	0.001	0.101	0.255	118.00
Large CHP	Northwest	2009	120	25	11,655	7%	5%	$ 756	$ 824	$ (17.75)	$ 14.22	0.001	0.050	0.255	118.00
Small Non-CT CHP	Northwest	2009	25	25	5,156	5%	10%	$ 782	$ 898	$ 0.17	$ 29.49	0.001	0.080	0.255	118.00
Small Industrial CHP	Northwest	2008	5	25	12,590	7%	2%	$ 1,265	$ 1,451	$ (0.28)	$ 7.15	0.001	0.138	0.255	118.00
Small Commercial CHP	Northwest	2008	1	25	10,035	3%	1%	$ 1,167	$ 1,339	$ (0.02)	$ 1.17	0.001	0.220	0.255	118.00
Fuel Cell - Small (Solid Oxide)	Northwest	2008	0.2	25	7,820	1%	2%	$ 1,362	$ 1,652	$ 0.03	$ 8.82	0.001	0.003	0.255	118.00
SCCT Aero	Northwest	2009	91	25	10,744	2%	10%	$ 605	$ 694	$ 6.13	$ 18.06	0.001	0.011	0.255	118.00
Intercooled Aero SCCT	Northwest	2009	90	25	9,436	7%	2%	$ 603	$ 692	$ 2.23	$ 25.06	0.001	0.011	0.255	118.00
Internal Combustion Engines	Northwest	2009	177	25	8,390	3%	1%	$ 712	$ 817	$ 5.20	$ 12.80	0.001	0.017	0.255	118.00
SCCT Frame (2 Frame "F")	Northwest	2009	350	35	11,509	5%	10%	$ 402	$ 461	$ 9.40	$ 5.00	0.001	0.050	0.255	118.00
CCCT (Wet "F" 1x1)	Northwest	2010	257	35	7,223	7%	5%	$ 720	$ 826	$ 2.25	$ 14.22	0.001	0.011	0.255	118.00
CCCT Duct Firing (Wet "F" 1x1)	Northwest	2010	58	35	8,868	7%	5%	$ 240	$ 275	$ 0.10	$ -	0.001	0.011	0.255	118.00
CCCT (Wet "F" 2x1)	Northwest	2010	518	35	7,164	7%	5%	$ 655	$ 752	$ 2.25	$ 8.64	0.001	0.011	0.255	118.00
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2010	116	35	8,868	7%	5%	$ 220	$ 252	$ 0.10	$ -	0.001	0.011	0.255	118.00
CCCT (Wet "G" 1x1)	Northwest	2010	343	35	7,075	7%	5%	$ 681	$ 781	$ 2.21	$ 10.75	0.001	0.011	0.255	118.00
CCCT Duct Firing (Wet "G" 1x1)	Northwest	2010	69	35	8,868	7%	5%	$ 252	$ 290	$ 0.10	$ -	0.001	0.011	0.255	118.00
Other- Renewables															
Oregon Wind	Northwest	2008	50	20	n/a	n/a	5%	$ 1,556	$ 1,919	$ -	$ 29.78	-	-	-	-
Biomass (closed loop)	Northwest	2010	100	35	10,979	5%	4%	$ 2,213	$ 2,563	$ 1.91	$ 4.12	0.062	0.350	0.600	205.39
Nuclear, Passive Safety	Northwest	2022	600	40	10,710	7%	8%	$ 2,382	$ 2,889	$ 0.38	$ 109.72	-	-	-	-
Compressed Air Energy Storage (CAES)	Northwest	2010	405	25	11,670	7%	10%	$ 603	$ 698	$ 4.76	$ 3.28	0.001	0.011	0.255	118.00
Customer Owned Standby Generation	Northwest	2008	40	20	10,500	n/a	n/a	$ 170	$ 170	$ 146.00	$ 3.50	0.058	0.231	n/a	190.00

Table 5.3 – Total Resource Cost for East Side Supply-Side Resource Options
(2006 Dollars)

Description	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs mills/kWh				Total Resource Cost (Mills/kWh)
	Total Capital Cost	Payment Factor	Annual Payment ($/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	Total	Tax Credits	Environmental	
East Side Options (4500')																
Coal																
Utah PC Supercritical 1 (600 MW)	$ 2,103	8.10%	$ 170.43	$ 35.65	$ 6.00	$ 41.65	$ 212.08	91%	26.49	187.20	17.16	$ 2.41	-	-	5.39	$ 51.46
Utah PC Supercritical 2 (600 MW)	$ 2,103	8.10%	$ 170.43	$ 35.65	$ 6.00	$ 41.65	$ 212.08	91%	26.49	187.20	17.16	$ 2.41	-	-	5.39	$ 51.46
Utah IGCC (Min. Carbon Prep/Level II Controls)	$ 2,479	7.82%	$ 193.86	$ 81.31	$ 6.00	$ 87.31	$ 281.17	89%	36.06	187.20	16.35	$ 1.10	-	-	4.83	$ 58.35
Utah IGCC (Min. Carbon Prep/Level II - no spare gas.)	$ 2,339	7.82%	$ 182.90	$ 76.71	$ 6.00	$ 82.71	$ 265.62	79%	38.38	187.20	16.35	$ 1.10	-	-	4.83	$ 60.66
Utah IGCC with Carbon Capture & Sequestration	$ 3,170	7.82%	$ 247.87	$ 114.50	$ 6.00	$ 120.50	$ 368.37	89%	47.25	187.20	18.56	$ 6.28	-	-	0.64	$ 72.74
Wyoming PC Supercritical (750 MW)	$ 2,093	8.10%	$ 169.61	$ 41.06	$ 6.00	$ 47.06	$ 216.67	91%	27.06	103.67	9.77	$ 2.08	-	-	5.54	$ 44.46
Wyoming IGCC (Min. Carbon Prep/Level II Controls)	$ 2,700	7.82%	$ 211.11	$ 81.32	$ 6.00	$ 87.32	$ 298.43	89%	38.28	103.67	9.24	$ 1.08	-	-	4.93	$ 53.53
Natural Gas																
Microturbine	$ 1,003	11.21%	$ 112.38	$ 200.00	$ 0.50	$ 200.50	$ 312.88	98%	36.45	693.70	89.39	$ 2.00	-	-	4.45	$ 139.37
Small Non-CT CHP	$ 884	9.84%	$ 87.01	$ 29.49	$ 0.50	$ 29.99	$ 117.01	85%	15.71	693.70	35.77	$ 0.20	-	-	1.75	$ 56.26
Small Industrial CHP	$ 1,561	9.84%	$ 153.64	$ 8.22	$ 0.50	$ 8.72	$ 162.36	90%	20.59	693.70	87.34	$ (0.32)	-	-	4.49	$ 119.03
Small Commercial CHP	$ 1,253	9.84%	$ 123.29	$ 1.35	$ 0.50	$ 1.85	$ 125.14	90%	15.87	693.70	69.61	$ (0.03)	-	-	3.84	$ 94.82
Fuel Cell - Small (Solid Oxide)	$ 1,745	8.50%	$ 148.23	$ 9.70	$ 0.50	$ 10.20	$ 158.43	97%	18.65	693.70	54.25	$ 0.03	-	-	2.46	$ 79.69
Fuel Cell - Large (Solid Oxide)	$ 1,236	8.50%	$ 105.01	$ 8.40	$ 0.50	$ 8.90	$ 113.91	95%	13.69	693.70	43.36	$ 0.03	-	-	1.97	$ 62.48
SCCT Aero	$ 752	9.51%	$ 71.53	$ 20.91	$ 0.50	$ 21.41	$ 92.94	21%	50.52	693.70	74.53	$ 7.08	0.15	-	3.41	$ 139.40
Intercooled Aero SCCT	$ 750	9.51%	$ 71.27	$ 29.02	$ 0.50	$ 29.52	$ 100.79	21%	54.79	693.70	65.46	$ 2.58	-	-	2.99	$ 129.21
Internal Combustion Engines	$ 885	9.51%	$ 84.14	$ 12.80	$ 0.50	$ 13.30	$ 97.44	94%	11.83	693.70	58.20	$ 5.20	-	-	2.68	$ 82.53
SCCT Frame (2 Frame "F")	$ 499	8.33%	$ 41.61	$ 5.78	$ 0.50	$ 6.28	$ 47.89	21%	26.03	693.70	79.84	$ 10.86	-	-	3.79	$ 124.53
CCCT (Wet "F" 1x1)	$ 895	8.62%	$ 77.16	$ 16.42	$ 0.50	$ 16.92	$ 94.08	56%	19.18	693.70	50.11	$ 2.60	-	-	2.29	$ 77.90
CCCT Duct Firing (Wet "F" 1x1)	$ 298	8.62%	$ 25.67	-	$ 0.50	$ 0.50	$ 26.17	16%	18.67	693.70	61.52	$ 0.11	-	-	2.81	$ 86.70
CCCT (Wet "F" 2x1)	$ 815	8.62%	$ 70.20	$ 9.98	$ 0.50	$ 10.48	$ 80.68	56%	16.45	693.70	49.69	$ 2.60	3.50	-	2.27	$ 74.71
CCCT Duct Firing (Wet "F" 2x1)	$ 273	8.62%	$ 23.56	-	$ 0.50	$ 0.50	$ 24.06	16%	17.17	693.70	61.52	$ 0.11	-	-	2.81	$ 85.19
CCCT (Wet "G" 1x1)	$ 847	8.62%	$ 72.96	$ 12.42	$ 0.50	$ 12.92	$ 85.88	56%	17.51	693.70	49.08	$ 2.55	-	-	2.25	$ 75.03
CCCT Duct Firing (Wet "G" 1x1)	$ 314	8.62%	$ 27.05	-	$ 0.50	$ 0.50	$ 27.55	16%	19.66	693.70	61.52	$ 0.11	-	-	2.81	$ 87.68
Other - Renewables																
SW Wyoming Wind	$ 2,011	9.48%	$ 190.70	$ 29.78	$ 0.50	$ 30.28	$ 220.98	35%	72.49	-	-	-	-	(20.65)	-	$ 55.13
Idaho Wind	$ 1,729	9.48%	$ 163.96	$ 29.78	$ 0.50	$ 30.28	$ 194.24	33%	68.23	-	-	-	-	(20.65)	-	$ 50.87
Geothermal, Dual Flash	$ 3,346	7.46%	$ 249.55	$ 22.60	$ 0.50	$ 23.10	$ 272.65	96%	32.32	-	21.13	$ 5.50	-	(20.65)	-	$ 38.30
Battery Storage	$ 1,400	8.51%	$ 119.15	$ 1.00	$ 0.50	$ 1.50	$ 120.65	21%	65.59	693.70	83.24	$ 10.00	-	-	8.62	$ 167.45
Pumped Storage	$ 1,191	7.86%	$ 93.62	$ 4.30	$ 1.35	$ 5.65	$ 99.27	20%	56.66	693.70	90.18	$ 4.30	-	-	9.340	$ 160.48
Compressed Air Energy Storage (CAES)	$ 753	8.69%	$ 65.45	$ 3.80	$ 1.35	$ 5.15	$ 70.60	25%	32.24	693.70	80.96	$ 5.50	-	-	3.704	$ 122.40
Nuclear, Passive Safety	$ 2,635	8.01%	$ 210.97	$ 109.72	$ 6.00	$ 115.72	$ 326.69	85%	43.87	-	6.63	$ 0.38	-	-	-	$ 50.88
Solar Thermal Trough with Natural Gas Backup	$ 3,939	7.87%	$ 310.11	$ 26.10	$ 6.00	$ 32.10	$ 342.21	21%	186.03	-	-	$ 3.10	-	-	-	$ 189.13

Table 5.4 – Total Resource Cost for West Side Supply-Side Resource Options
(2006 Dollars)

Description	Capital Cost $/kW: Total Capital Cost	Capital Cost $/kW: Payment Factor	Capital Cost $/kW: Annual Payment ($/kW-Yr)	Fixed Cost: Fixed O&M ($/kW-Yr) O&M	Fixed Cost: Fixed O&M ($/kW-Yr) Other	Fixed Cost: Fixed O&M ($/kW-Yr) Total	Fixed Cost: Total Fixed ($/kW-Yr)	Capacity Factor	Convert to Mills: Total Fixed (Mills/kWh)	Convert to Mills: Levelized Fuel ¢/mmBtu	Convert to Mills: Levelized Fuel Mills/kWh	Variable Costs mills/kWh: O&M	Variable Costs mills/kWh: Total	Variable Costs mills/kWh: Tax Credits	Variable Costs mills/kWh: Environmental	Total Resource Cost (Mills/kWh)
West Side Options (1500')																
Natural Gas																
Microturbine	$ 912	11.21%	$ 102.16	$ 181.82	$ 0.50	$ 182.32	$ 284.48	98%	33.14	699.25	90.10	$ 1.82	-	-	4.45	$ 136.72
Fuel Cell - Small (Solid Oxide)	$ 1,586	8.50%	$ 134.76	$ 8.82	$ 0.50	$ 9.32	$ 144.08	97%	16.96	699.25	54.68	$ 0.03	-	-	2.46	$ 78.51
SCCT Aero	$ 684	9.51%	$ 65.02	$ 19.01	$ 0.50	$ 19.51	$ 84.53	21%	45.95	699.25	75.13	$ 6.44	-	-	3.41	$ 134.53
Intercooled Aero SCCT	$ 682	9.51%	$ 64.79	$ 26.38	$ 0.50	$ 26.88	$ 91.68	21%	49.83	699.25	65.98	$ 2.35	-	-	2.99	$ 124.32
Internal Combustion Engines	$ 805	9.51%	$ 76.49	$ 12.80	$ 0.50	$ 13.30	$ 89.79	94%	10.90	699.25	58.67	$ 5.20	-	-	2.68	$ 82.15
SCCT Frame (2 Frame "F")	$ 454	8.33%	$ 37.83	$ 5.25	$ 0.50	$ 5.75	$ 43.58	21%	23.69	699.25	80.48	$ 9.87	-	-	3.79	$ 121.54
CCCT (Wet "F" 1x1)	$ 814	8.62%	$ 70.15	$ 14.93	$ 0.50	$ 15.43	$ 85.57	56%	17.44	699.25	50.51	$ 2.36	-	-	2.29	$ 76.36
CCCT Duct Firing (Wet "F" 1x1)	$ 271	8.62%	$ 23.34	-	$ 0.50	$ 0.50	$ 23.84	16%	17.01	699.25	62.01	$ 0.10	-	-	2.81	$ 85.37
CCCT (Wet "F" 2x1)	$ 741	8.62%	$ 63.82	$ 9.07	$ 0.50	$ 9.57	$ 73.39	56%	14.96	699.25	50.09	$ 2.36	-	-	2.27	$ 73.42
CCCT Duct Firing (Wet "F" 2x1)	$ 249	8.62%	$ 21.42	-	$ 0.50	$ 0.50	$ 21.92	16%	15.64	699.25	62.01	$ 0.10	-	-	2.81	$ 84.00
CCCT (Wet "G" 1x1)	$ 770	8.62%	$ 66.33	$ 11.29	$ 0.50	$ 11.79	$ 78.12	56%	15.92	699.25	49.47	$ 2.32	-	-	2.25	$ 73.64
CCCT Duct Firing (Wet "G" 1x1)	$ 285	8.62%	$ 24.59	-	$ 0.50	$ 0.50	$ 25.09	16%	17.90	699.25	62.01	$ 0.10	-	-	2.81	$ 86.27
Other - Renewables																
Oregon Wind	$ 1,737	9.48%	$ 164.75	$ 29.78	$ 22.22	$ 52.00	$ 216.75	34%	72.35	-	-	-	-	(20.65)	-	$ 54.99
Geothermal, Dual Flash	$ 3,346	7.46%	$ 249.55	$ 22.60	$ 0.50	$ 23.10	$ 272.65	96%	32.32	-	21.13	$ 5.50	-	(20.65)	-	$ 38.30
Compressed Air Energy Storage (CAES)	$ 685	8.69%	$ 59.50	$ 3.45	$ 1.35	$ 4.80	$ 64.31	25%	29.36	699.25	81.60	$ 5.00	-	-	3.70	$ 119.67
West Side Options (Sea Level)																
Coal																
Washington IGCC (Min. Carbon Prep/Level II Controls)	$ 2,479	7.82%	$ 193.86	$ 81.31	$ 6.00	$ 87.31	$ 281.17	89%	36.06	150.00	13.10	$ 1.10	-	-	4.83	$ 55.10
Natural Gas																
Microturbine	$ 866	11.21%	$ 97.06	$ 172.73	$ 0.50	$ 173.23	$ 270.28	98%	31.48	699.25	90.10	$ 1.73	-	-	4.45	$ 134.98
Large CHP	$ 790	9.84%	$ 77.75	$ 14.22	$ 0.50	$ 14.72	$ 92.46	89%	11.93	699.25	81.50	$ (17.75)	-	-	3.84	$ 86.23
Small Non-CT CHP	$ 840	9.84%	$ 82.66	$ 29.49	$ 0.50	$ 29.99	$ 112.65	85%	15.13	699.25	36.05	$ 0.17	-	-	1.75	$ 55.99
Small Industrial CHP	$ 1,358	9.84%	$ 133.60	$ 7.15	$ 0.50	$ 7.65	$ 141.25	90%	17.92	699.25	88.04	$ (0.28)	-	-	4.49	$ 117.22
Small Commercial CHP	$ 1,253	9.84%	$ 123.29	$ 1.17	$ 0.50	$ 1.67	$ 124.96	90%	15.85	699.25	70.17	$ (0.02)	-	-	3.84	$ 95.46
Fuel Cell - Small (Solid Oxide)	$ 1,507	8.50%	$ 128.02	$ 8.82	$ 0.50	$ 9.32	$ 137.34	97%	16.16	699.25	54.68	$ 0.03	-	-	2.46	$ 77.71
SCCT Aero	$ 650	9.51%	$ 61.77	$ 18.06	$ 0.50	$ 18.56	$ 80.33	21%	43.67	699.25	75.13	$ 6.13	-	-	3.41	$ 131.93
Intercooled Aero SCCT	$ 647	9.51%	$ 61.55	$ 25.06	$ 0.50	$ 25.56	$ 87.12	21%	47.36	699.25	65.98	$ 2.23	-	-	2.99	$ 121.73
Internal Combustion Engines	$ 764	9.51%	$ 72.67	$ 12.80	$ 0.50	$ 13.30	$ 85.97	94%	10.44	699.25	58.67	$ 5.20	-	-	2.68	$ 81.68
SCCT Frame (2 Frame "F")	$ 431	8.33%	$ 35.94	$ 5.00	$ 0.50	$ 5.50	$ 41.44	21%	22.53	699.25	80.48	$ 9.40	-	-	3.79	$ 119.90
CCCT (Wet "F" 1x1)	$ 773	8.62%	$ 66.64	$ 14.22	$ 0.50	$ 14.72	$ 81.36	56%	16.58	699.25	50.51	$ 2.25	-	-	2.29	$ 75.39
CCCT Duct Firing (Wet "F" 1x1)	$ 257	8.62%	$ 22.17	-	$ 0.50	$ 0.50	$ 22.67	16%	16.18	699.25	62.01	$ 0.10	-	-	2.81	$ 84.53
CCCT (Wet "F" 2x1)	$ 703	8.62%	$ 60.63	$ 8.64	$ 0.50	$ 9.14	$ 69.77	56%	14.22	699.25	50.09	$ 2.25	-	-	2.27	$ 72.56
CCCT Duct Firing (Wet "F" 2x1)	$ 236	8.62%	$ 20.35	-	$ 0.50	$ 0.50	$ 20.85	16%	14.88	699.25	62.01	$ 0.10	-	-	2.81	$ 83.24
CCCT (Wet "G" 1x1)	$ 731	8.62%	$ 63.01	$ 10.75	$ 0.50	$ 11.25	$ 74.26	56%	15.14	699.25	49.47	$ 2.21	-	-	2.25	$ 72.74
CCCT Duct Firing (Wet "G" 1x1)	$ 271	8.62%	$ 23.36	-	$ 0.50	$ 0.50	$ 23.86	16%	17.02	699.25	62.01	$ 0.10	-	-	2.81	$ 85.38
Other- Renewables																
Oregon Wind	$ 1,729	9.48%	$ 163.96	$ 29.78	$ 22.22	$ 52.00	$ 215.96	34%	72.51	-	-	-	-	(20.65)	-	$ 55.15
Biomass (closed loop)	$ 2,388	7.46%	$ 178.11	$ 4.12	$ 0.50	$ 4.62	$ 182.73	91%	22.82	300.00	32.94	$ 1.91	-	(20.65)	7.42	$ 44.44
Nuclear, Passive Safety	$ 2,635	8.01%	$ 210.97	$ 109.72	$ 6.00	$ 115.72	$ 326.69	85%	43.87	-	6.35	$ 0.38	-	-	-	$ 50.60
Compressed Air Energy Storage (CAES)	$ 651	8.69%	$ 56.53	$ 3.28	$ 1.35	$ 4.63	$ 61.16	25%	27.93	699.25	81.60	$ 4.76	-	-	3.70	$ 117.99
Customer Owned Standby Generation	$ 170	11.00%	$ 18.70	$ 3.50	$ 0.50	$ 4.00	$ 22.70	25%	10.36	-	-	$ 146.00	-	-	6.22	$ 162.59

Resource Descriptions

Coal

Potential coal resources are shown in the supply-side resource options tables as supercritical pulverized coal boilers in Utah[31] and Wyoming, and IGCC facilities in Utah, Wyoming, and West Main. Supercritical technology was chosen over subcritical technology for pulverized coal for a number of reasons. Increasing coal costs are making the added efficiency of the supercritical technology cost-effective for long-term operation. Additionally, there is a greater competitive marketplace for large supercritical boilers than for large subcritical boilers. Increasingly, large boiler manufacturers only offer supercritical boilers in the 500+ megawatt sizes. Due to the increased efficiency of supercritical boilers, overall emission quantities are smaller than for a similarly sized subcritical unit. Compared to subcritical boilers, supercritical boilers can follow loads better, ramp to full load faster, use less water, and require less steel for construction. The smaller steel requirements have also leveled the construction cost estimates for the two coal technologies. The costs for a supercritical pulverized coal facility reflect the cost of adding a new unit at an existing site. PacifiCorp does not expect a significant difference in cost for a multiple unit at a new site versus the cost of a single unit addition at an existing site.

Carbon dioxide capture and sequestration technology represents a potential cost for new and existing coal plants if future regulations require it. Research projects are underway to develop more cost-effective methods of capturing carbon dioxide from the flue gas of conventional boilers. One such concept involves the use of ammonia and chilling the flue gas. ALSTOM, a major supplier of utility boilers, gas-fired and steam turbine-generators, and air quality control equipment for power generation applications, has licensed a chilled ammonia process for the capture of CO_2 from the flue gas from pulverized coal and natural gas-fired combined-cycle plants. The process is expected to have application for both new generating units and retrofit applications. This technology holds the promise that the cost of energy from a pulverized coal plant with CO_2 capture will be competitive with the cost of energy from an integrated gasification combined cycle plant with CO_2 capture.[32]

ALSTOM is currently working on a 5 megawatt (thermal) demonstration scale facility along with the Electric Power Research Institute and We Energies that is to be constructed at We Energies' Pleasant Prairie Plant. PacifiCorp is participating through EPRI in this CO_2 Pilot Capture study; this participation will provide the company with access to summary analysis, performance, and cost projections of the technology. Startup of the project is expected in mid-2007 with extensive testing for at least one year. American Electric Power (AEP) recently announced plans

[31] Although the Supply-side Resource Options table shows the two Utah supercritical coal resources at 600 MW each, for modeling purposes, the company assumed that the second Utah resource would be acquired as a 57% share of 600 MW, or 340 MW.

[32] The chilled ammonia process entails the use of ammonia in place of amine-based processes. Most studies done to date on CO_2 capture from combustion gases have been based on the use of amine-based systems. Reagent costs are expected to be lower since ammonia is a reasonably low-cost commodity chemical. The use of ammonia instead of amine-based systems is expected to minimize the steam requirement associated with regenerating the solvent. This reduced steam requirement mitigates the impact on the net capability of the unit. Chilling the flue gas to low temperatures greatly reduces the volume of flue gas that has to be treated, thereby reducing equipment and process costs. The regeneration part of the process also operates at high pressure which reduces the electrical load associated with compression of the recovered CO_2.

to install a 30 megawatt (thermal) demonstration in 2009 and a 200 megawatt equivalent demonstration by 2011. Such large demonstrations will verify the commercial status of this process. It is expected that the chilled ammonia system will be able to remove approximately 90% of the CO_2 in the flue gas.

PacifiCorp and its parent company MEHC are monitoring CO_2 capture technologies for possible retrofit opportunities at its existing coal-fired fleet, as well as applicability for future coal plants that could serve as cost-effective alternatives to IGCC plants if CO_2 removal becomes necessary in the future.

An alternative to supercritical pulverized-coal technology for coal-based generation would be the use of IGCC technology. A significant advantage for IGCC when compared to conventional pulverized coal with amine-based carbon capture is the reduced cost of capturing carbon dioxide from the process. Gasification plants have been built and demonstrated around the world, primarily as a means of producing chemicals from coal. Only a limited number of IGCC plants have been constructed specifically for power generation. In the United States, these facilities have been demonstration projects and cost significantly more than conventional coal plants in both capital and operating costs. These projects have been constructed with significant funding from the federal government. A number of IGCC technology suppliers have teamed up with large constructor to form consortia who are now offering to build IGCC plants. A few years ago, these consortia were willing to provide IGCC plants on a lump-sum, turn-key basis. However, in today's market, the willingness of these consortia to design and construct IGCC plants on lump-sum turn key basis is in question. An extensive and costly front-end engineering design (FEED) study is required to obtain reasonably accurate estimates of the cost of building an IGCC plant. In 2005-2006, PacifiCorp contracted with Worley Parsons to study the cost of an IGCC located either in Utah or Wyoming. The costs presented in the supply-side resource options tables reflect the general results of that study effort.

An IGCC plant can be installed with a number of different configurations. Three different configurations are presented in the supply-side resource options table for an IGCC installed at a Utah location. One configuration involves installation of Level II emission controls with a spare gasifier and space provisions for future installation of carbon capture equipment. Level II emission controls would include a selective catalytic reduction (SCR) system for enhanced NOx control. A Level II emission control system would achieve emission levels close to those of a natural gas-fired combined cycle plant. Installation of a spare gasifier would enable availability and capacity factors close to a conventional pulverized-coal plant. Another IGCC configuration presented in the supply-side resource options table is for a plant without the spare gasifier. The third configuration presented is for an IGCC plant with carbon capture. The carbon capture case assumes a cost of $5/MWh for carbon dioxide sequestration; this cost includes the transportation, injection, storage, and monitoring of the carbon dioxide in a local geological formation.

PacifiCorp is involved in a number of potential IGCC projects that are in various stages of development. Major project development efforts are the Energy Northwest Pacific Mountain Energy Center (PMEC) and the Wyoming Infrastructure Authority (EPAct Section 413) project.

In March 2006, PacifiCorp responded with an expression of interest to Energy Northwest's invitation to participate in the PMEC project. Energy Northwest is currently in active negotiations with the two major technology consortia for the next stage of engineering and commercial efforts (Conoco-Phillips/Fluor/Siemens and General Electric/Bechtel), and the project is now going through the Energy Facility Site Evaluation Council (EFSEC) review process. The state of Washington recently passed Senate Bill 6001—climate change legislation that, among other provisions, implements a generation CO_2 emission standard of 1,100 lbs of CO_2 per MWh (or less) or permanent sequestration which meets the same level. Energy Northwest is currently evaluating options that would allow the PMEC clean coal project to satisfy these emissions levels.

PacifiCorp was recently selected by the Wyoming Infrastructure Authority (WIA) to participate in joint project development activities for an IGCC facility in Wyoming. The ultimate goal is to develop a Section 413 project under the EPact. PacifiCorp will commission and manage feasibility studies with one or more technology suppliers/consortia for an IGCC facility at its Jim Bridger plant with some level of carbon capture. Alternate Wyoming sites may be considered. During this feasibility study stage, WIA will seek federal funding to support the next stage of development, which would include a detailed Front End Engineering Design (FEED) study.

In addition to the PMEC and Wyoming IGCC projects, PacifiCorp has also been in discussions with a number of other proposed IGCC projects. These include Summit Power's IGCC project at Clatskanie, Oregon, Mission's IGCC project at Wallula, Washington, and Xcel's IGCC project in Colorado.

Finally, PacifiCorp actively participates in the Electric Power Research Institute's CoalFleet program. CoalFleet is a major utility and technology supplier-sponsored initiative to accelerate development, demonstration, and deployment of IGCC. PacifiCorp is a member of the Gasification User's Association. In addition, PacifiCorp communicates regularly with the primary gasification technology suppliers, constructors, and other utilities.

Natural Gas

Natural gas generation options are numerous and a limited number of representative technologies are included in the supply-side resource options table. Simple cycle and combined cycle combustion turbines are included as well as distributed generation and CHP systems which are discussed below.

Combustion turbine options include both simple cycle and combined cycle configurations. The simple cycle options include traditional frame machines as well as aero-derivative combustion turbines. Two aero-derivative machine options were chosen. The General Electric LM6000 machines are flexible, high efficiency machines and can be installed with high temperature SCR systems, which allow them to be located in areas with air emissions concerns. These types of gas turbines are identical to those recently installed at Gadsby and West Valley. LM6000 gas turbines have quick-start capability (less than 10 minutes to full load) and higher heating value heat rates near 10,000 Btu/kWh. Also selected for the supply-side resource options table is General Electric's new LMS-100 gas turbine. This machine was recently installed for the first time in a commercial venture. It is a cross between a simple-cycle aero-derivative gas turbine and a frame machine with significant amount of compressor intercooling to improve efficiency. The machines have higher heating value heat rates of less than 9,500 Btu/kWh and similar starting capabilities as the LM6000 with significant load following capability (up to 50 megawatt per minute).

Frame simple cycle machines are represented by the "F" class technology. These machines are about 150 megawatts at western elevations, and can deliver good simple cycle efficiencies.

Other natural gas-fired generation options include internal combustion engines and fuel cells. Internal combustion engines are represented by a large power plant consisting of 14 machines at 10.9 megawatts. These machines are spark-ignited and have the advantages of a relatively attractive heat rate, a low emissions profile, and a high level of availability and reliability due to the large number of machines. At present, fuel cells hold less promise due to high capital cost, partly attributable to the lack of production capability and continued development. Fuel cells are not ready for large scale deployment and are not considered available as a supply-side option until after 2012.

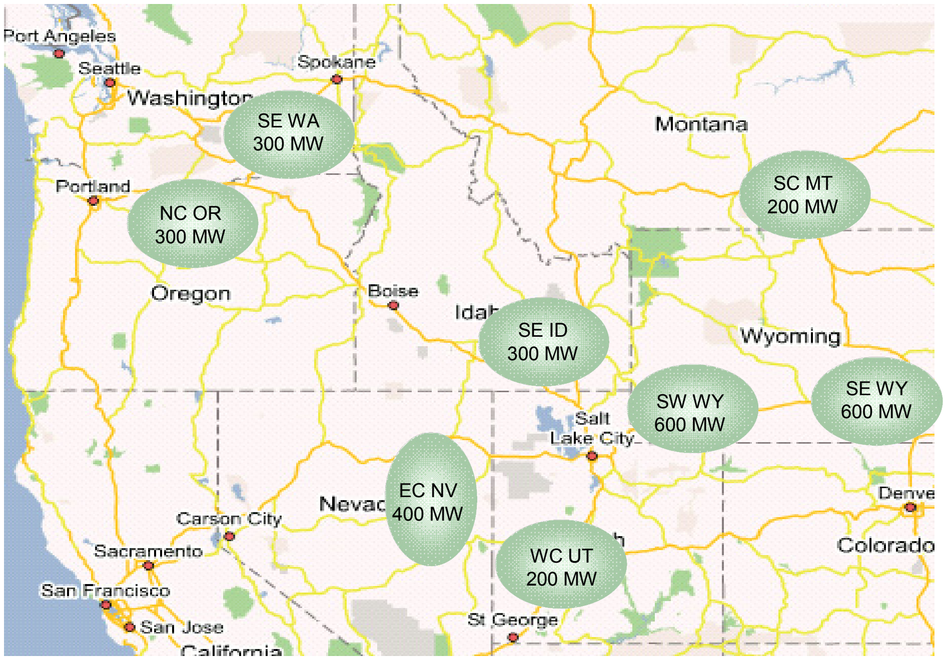
Combined cycle power plants options have been limited to 1x1 and 2x1 applications of "F" style combustion turbines and a "G" 1x1 facility. The "F" style machine options would allow an expansion of the Lake Side facility. Both the 1x1 and 2x1 configurations are included to give some flexibility to the portfolio planning. Similarly, the "G" machine has been added to take advantage of the improved heat rate available from these more advanced gas turbines. The "G" machine is only presented as a 1x1 option to keep the size of the facility reasonable for selection as a portfolio option. These natural gas technologies are considered mature and installation lead times and capital costs are well known. The capital cost pressure currently being observed with constructing large coal-based generation plants is also being experienced with natural gas-fired plants. The increased cost of natural gas has slowed the building of natural gas power plants in recent years. Over the past year, natural-gas-based resources have not seen the same level of cost increases as coal-based generation resources. However, this is expected to change; the same market forces that are affecting the cost of large coal-based projects also impacts the demand for major equipment, commodities, specialty steels, shop space, and craft labor needed for the construction of natural gas based resources.

Wind

Wind power has experienced rapid development in the U.S., as well as the Northwest. The renewal of the investment tax credit with the Energy Policy Act of 2005 has made the availability of wind turbines an increasingly critical issue. The cost for wind turbines has increased significantly in recent months due to the demand for these machines.

The overall strategy for wind project representation was to develop a set of proxy wind sites composed of 100 nameplate megawatt blocks that could be selected as distinct resource options in the Capacity Expansion Module. (Note that the 100-megawatt size reflects a suitable average size for modeling purposes, and does not imply that acquisitions are of this size.) Figure 5.1 shows the general regions in which wind resources were assumed to be available and the quantity limits available to CEM for selection.

Figure 5.1 – Proxy Wind Sites and Maximum Capacity Availabilities



For other wind resource attributes, the company used multiple sources to derive attributes. PacifiCorp has been very active in purchasing wind projects in the last year. This has given the company considerable market knowledge of the current cost of wind development. Consequently, wind resources were developed primarily from PacifiCorp experiences with wind developers and from responses to the 2003 renewable resource request for proposals. The EPRI TAG database was also used for certain cost figures, such as operation and maintenance costs. These costs were adjusted for current market conditions.

For modeling purposes, it was deemed advantageous to represent wind projects as realistically as possible by capturing the fluctuation of wind generation on an hourly basis, capturing the system costs and effects of the variability, seasonality, and diurnal shape of wind generation. These attributes and the methodologies used to derive them are discussed in Appendix J.

Other Renewable Resources

Other renewable generation resources included in the supply-side resource options table include geothermal, biomass, landfill gas, waste heat and solar. The financial attributes of these renewable options are based on the TAG database and have been adjusted based on PacifiCorp's recent construction and study experience.

The geothermal resource is a dual flash design with a wet cooling tower. This concept would be similar to an expansion of the Blundell Plant.[33] Speculative risks associated with steam field development, as well as recent escalation in drilling costs, are not captured in the geothermal cost characterization. Note that at the time that PacifiCorp was deciding how to address renewable

[33] A single flash expansion study was performed for Blundell unit 3 and filed with the state commissions in March 2007. The report is available on the Utah Public Service Commissions web site at: http://www.psc.state.ut.us/elec/05docs/0503554/3-20-07Exhibit%20B.doc.

resources in the IRP models, the renewable production tax credit was in effect only through the end of 2007, and the company did not include the credit in its geothermal project economic analyses. This treatment reflects the view that year-to-year tax credit extensions do not benefit projects with long development periods typical of a new geothermal plant.

The biomass project would involve the combustion of whole trees that would be grown in a plantation setting, presumably in the Pacific Northwest. The TAG database used a western Washington site. The solar resource available in the TAG database is a solar thermal system using parabolic trough technology with natural gas backup. Such systems have been installed in the southern California desert for many years. Cost and performance of these trough systems are well known.

Combined Heat and Power and Other Distributed Generation Alternatives

A number of different CHP applications were developed. These options were not derived from the EPRI TAG since the license purchased from EPRI was for larger power generation applications. Costs for the CHP options listed come from a 2003 paper from the National Renewable Energy Laboratory (NREL) entitled "Gas-fired Distributed Energy Resource Technology Characterizations", and were adjusted for recent construction cost increases. CHP options include small (one megawatt or less) internal combustion engines with water jacket heat recovery, small (five megawatts or less) combustion turbines with exhaust gas heat recovery, non-combustion turbine based steam turbines (topping turbine cycle) systems to utilize process steam in industrial applications, and larger (40 to 120 megawatts) combustion turbines with significant steam based heat recovery from the flue gas. A large CHP concept has not been included in PacifiCorp's eastern service territory due to a lack of large potential industrial applications. These CHP opportunities are site-specific, and the generic options presented in the supply-side resource options table are not intended to represent any particular project or opportunity.

In order to derive an estimate of potential CHP capacity availability within PacifiCorp's service territory for modeling purposes, PacifiCorp surveyed its Customer Account Managers for project opportunities and reviewed existing customer account data. A list of strong CHP prospects was developed. Based on the generic CHP resource capacities used in the supply-side resource options tables, PacifiCorp determined the number of CHP resources to include as options for selection by the Capacity Expansion Module. Table 5.5 profiles these CHP options by east and west-side location.

Table 5.5 – CHP Potential Prospects

Location	Strong Prospects (MW)	CHP 25 MW Unit	CHP 5 MW Unit	Total CHP Capacity Modeled (MW)
East	103	3 units	5 units	100
West	66	2 units	2 units	60

Energy Storage

The storage of energy is represented in the supply-side resource options table with three systems. The three systems are advanced battery applications, pumped hydro and compressed air energy storage. These technologies convert off-peak capacity to on-peak energy and thereby reduce the quantity of required overall capacity installed for peaking needs. The concepts use TAG data and have been adjusted to account for current construction market conditions. Battery applications are typically smaller systems (less than 10 megawatts) which can have the most benefit in a smaller local area. Pumped hydro is dependant on a good site combined with the ability to permit the facility, a process that can take many years to accomplish. PacifiCorp does not have any specific pumped hydro projects under development. Compressed air energy storage (CAES) can be an attractive means of utilizing intermittent energy. In a CAES plant, off-peak energy is used to pressurize an underground cavern. The pressurized air would then feed the power turbine portion of a combustion turbine saving the energy normally used in combustion turbine to compress air. CAES plants operate on a simple cycle basis and therefore displace peaking resources. A CAES plant could be built in conjunction with wind resources to level the production for such an intermittent resource. A CAES plant, whether associated with wind or not, would have to stand on its own for cost-effectiveness.

Nuclear
An emissions-free nuclear plant has been included in the supply-side resource options table. This option is based on the TAG database as well as information from a paper prepared by the Uranium Information Centre Ltd., "The Economics of Nuclear Power," April 2006. A 600 megawatt plant is characterized, utilizing advanced nuclear plant designs. Nuclear power is considered a viable option in the PacifiCorp service territory on or after 2018.

DEMAND-SIDE RESOURCES

Resource Selection Criteria

For the 2007 IRP, PacifiCorp evaluated and handled each class of DSM based on its characteristics and current availability. The company presented its proposed DSM resource representation and modeling methodology at a DSM technical workshop held on February 10, 2006, and considered public feedback in developing its final scheme. The following is a summary, by DSM class, of how the DSM options were selected for evaluation in the IRP.

Class 1 Demand-side Management
To address Class 1 programs (fully dispatchable or scheduled firm), the company commissioned Quantec LLC to construct proxy supply curves. (See Appendix B for the entire Quantec DSM supply curve report.) The supply curves targeted PacifiCorp's existing program expansion opportunities (e.g., air conditioning load control and irrigation load management) and new program opportunities identified as achievable. For modeling purposes, the Class 1 DSM opportunities were combined into the following five subcategories:

- **Subcategory 1** – Fully dispatchable winter programs, such as space heating
- **Subcategory 2** – Fully dispatchable summer programs, such as air conditioning, water heating, and pool pumps
- **Subcategory 3** – Fully dispatchable, large commercial and industrial, with a focus on adjustment of the heating, ventilation, and air conditioning (HVAC) equipment during the top summer hours
- **Subcategory 4** – Scheduled firm – irrigation

- **Subcategory 5** – Thermal energy storage, small commercial and industrial, with a focus on cooling systems for summer hours

Class 2 Demand-side Management
For Class 2 programs (non-dispatchable, firm energy efficiency programs), PacifiCorp updated and added new sample load shapes to reflect energy efficiency program opportunities in the market as identified by recent studies such as the Northwest Power Planning Council's 5th Power Plan. For example, based on its review, the company determined that residential lighting load shapes for the west and east control areas should be added. Table 5.6 lists the load shapes adopted for the 2007 IRP. Chapter 6 discusses how these sample load shapes were used to develop cost-effectiveness values of additional Class 2 resources.

Note that Class 2 DSM was not included as a resource option in portfolio modeling. The company is working to complete a more comprehensive system-wide demand-side management potential study scheduled to be completed by June 2007. This study will be used to develop modeled resource options for Classes 1, 2 and 3 for the next IRP.

Table 5.6 – Sample Load Shapes Developed for 2007 IRP Decrement Analysis

East	West
commercial cooling	commercial cooling
commercial lighting	commercial lighting
residential cooling	residential cooling
system load	system load
residential lighting*	residential lighting*
residential – whole house (including AC)*	residential - heating*

* New sample load shapes for the 2007 IRP

Class 3 Demand-side Management
For Class 3 DSM (price responsive programs), PacifiCorp commissioned Quantec to develop proxy supply curves for three Class 3 program concepts: curtailable rates, critical peak pricing, and demand buyback/bidding (DBB) products (See Appendix B). As with the Class 1 DSM resources, the company obtained and considered public feedback from its February 2006 DSM workshop in selecting these Class 3 DSM resources for the IRP.

Class 4 Demand-side Management
Class 4 resources are sought by the company. However, these resources are not currently taken into consideration within the 2007 IRP because they cannot be relied upon for planning purposes or cannot be easily quantified. Over time, most Class 4 DSM savings manifest themselves within the company's loads and load forecasts.

Resource Options and Attributes

Class 1 Demand-side Management
Tables 5.7 and 5.8 summarize the key attributes for the five DSM Class 1 program subcategories listed above for the west and east control areas respectively. Appendix B provides more information on how the attributes were derived. Attributes are provided for three scenarios: low, base,

and high achievable potential. These scenarios reflect PacifiCorp assumed on-peak electricity market prices of $40/MWh, $60/MWh, and $100/MWh respectively, as well as incrementally higher PacifiCorp marketing efforts, program costs, and customer participation levels. As already noted, Quantec developed these attributes for creation of PacifiCorp DSM resources for portfolio modeling.[34] The sources for the DSM attributes are Figures B.20 and B.21 in Appendix B, reflecting the "no metering" cost assumptions (Also see the "Treatment of Metering Cost" section in Appendix B.)

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Table 5.7 – Class 1 DSM Program Attributes, West Control Area

Attributes	Fully Dispatchable-Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -
Demand Reduction Period (Hours)	2	2	4	6	6
Start Year	2009	2009	2009	2009	2009
BASE					
Total Achievable Potential –Maximum (MW)	21	8	1	32	3
Resource Costs ($/kW/yr)	$ 75	$ 57	$ 89	$ 28	$ 119
LOW					
Total Achievable Potential --Maximum (MW)	11	2	0	26	3
Resource Costs ($/kW/yr)	$ 57	$ 60	$ 185	$ 29	$ 116
HIGH					
Total Achievable Potential --Maximum (MW)	32	10	3	38	4
Resource Costs ($/kW/yr)	$ 83	$ 69	$ 104	$ 37	$ 121
Hours Available by Month					
January	3	-	-	-	-
February	-	-	-	-	-
March	-	-	-	-	-
April	-	-	-	-	240
May	-	-	-	-	186
June	-	8	8	96	180
July	-	46	46	96	186
August	-	33	33	96	186
September	-	-	-	48	180
October	-	-	-	-	279
November	-	-	-	-	-
December	84	-	-	-	-

[34] Quantec's DSM resource attributes were considered interim information needed to complete the 2007 IRP while the company works to complete a more comprehensive system-wide demand-side management potential study scheduled to be completed by June 2007.

Table 5.8 – Class 1 DSM Program Attributes, East Control Area

Attributes	Fully Dis-patchable-Winter	Fully Dis-patchable - Summer	Fully Dispatch-able - Large C&I	Scheduled Firm - Irri-gation	Thermal Energy Storage
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -
Demand Reduction Period (Hours)	2	2	4	6	6
Start Year	2009	2009	2009	2009	2009
BASE					
Total Achievable Potential –Maximum (MW)	16	48	2	15	6
Resource Costs ($/kW/yr)	$ 75	$ 58	$ 82	$ 27	$ 117
LOW					
Total Achievable Potential - -Maximum (MW)	8	13	0	3	4
Resource Costs ($/kW/yr)	$ 57	$ 52	$ 159	$ 28	$ 115
HIGH					
Total Achievable Potential - -Maximum (MW)	25	66	7	28	7
Resource Costs ($/kW/yr)	$ 83	$ 71	$ 101	$ 36	$ 118
Hours Available by Month					
January	3	-	-	-	-
February	-	-	-	-	-
March	-	-	-	-	-
April	-	-	-	-	240
May	-	-	-	-	186
June	-	8	8	96	180
July	-	46	46	96	186
August	-	33	33	96	186
September	-	-	-	48	180
October	-	-	-	-	279
November	-	-	-	-	-
December	84	-	-	-	-

Class 2 Demand-side Management

Figures 5.2 and 5.3 show the hourly end use shapes used for the Class 2 DSM decrement analysis. Figure 5.2 plots the hourly end use shapes for the peak day use for each of the 10 end uses. Figure 5.3 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. The megawatt scale on the y–axis of Figures 5.2 and 5.3 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 5.2 – DSM Decrement, Daily End Use Shape (megawatts)

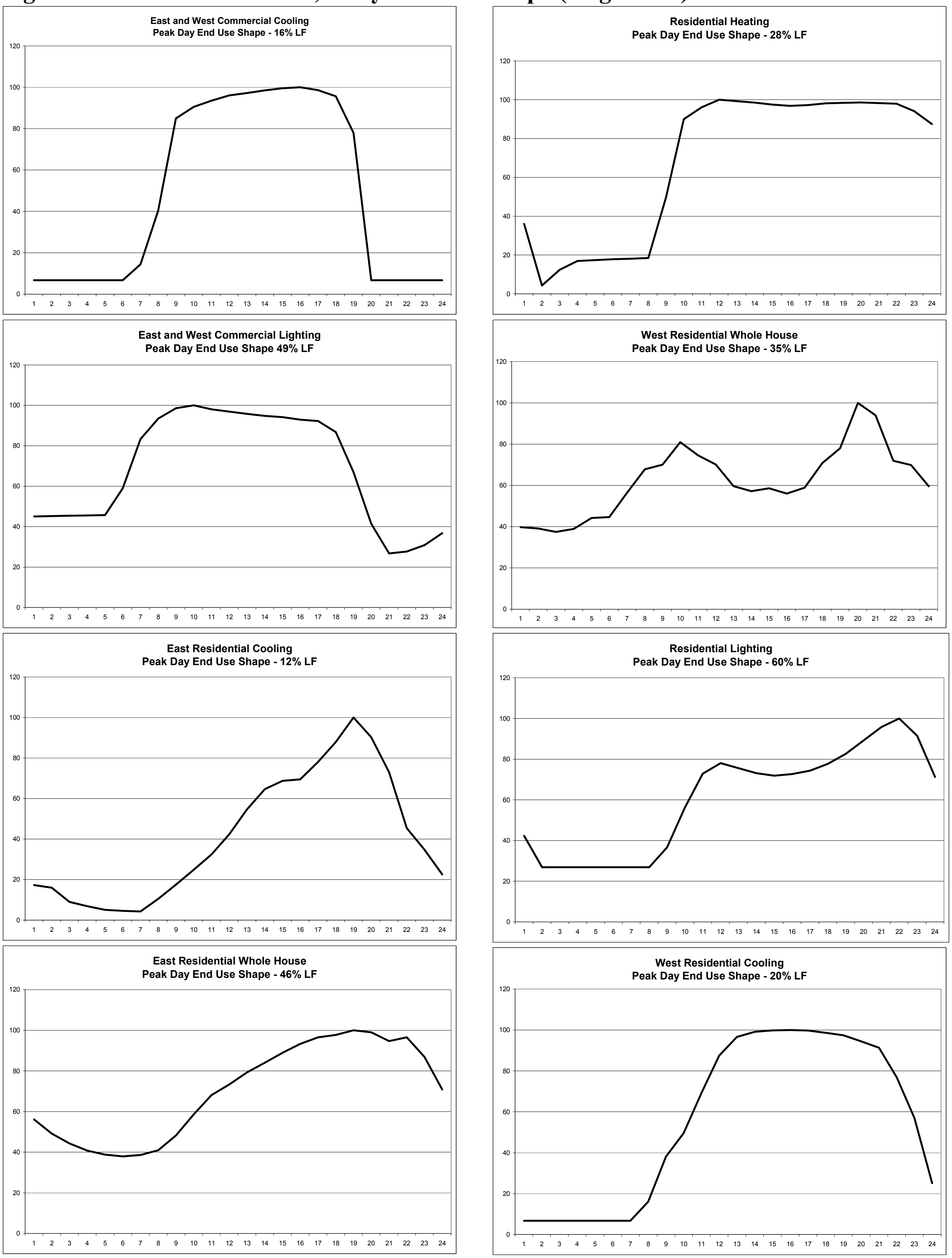
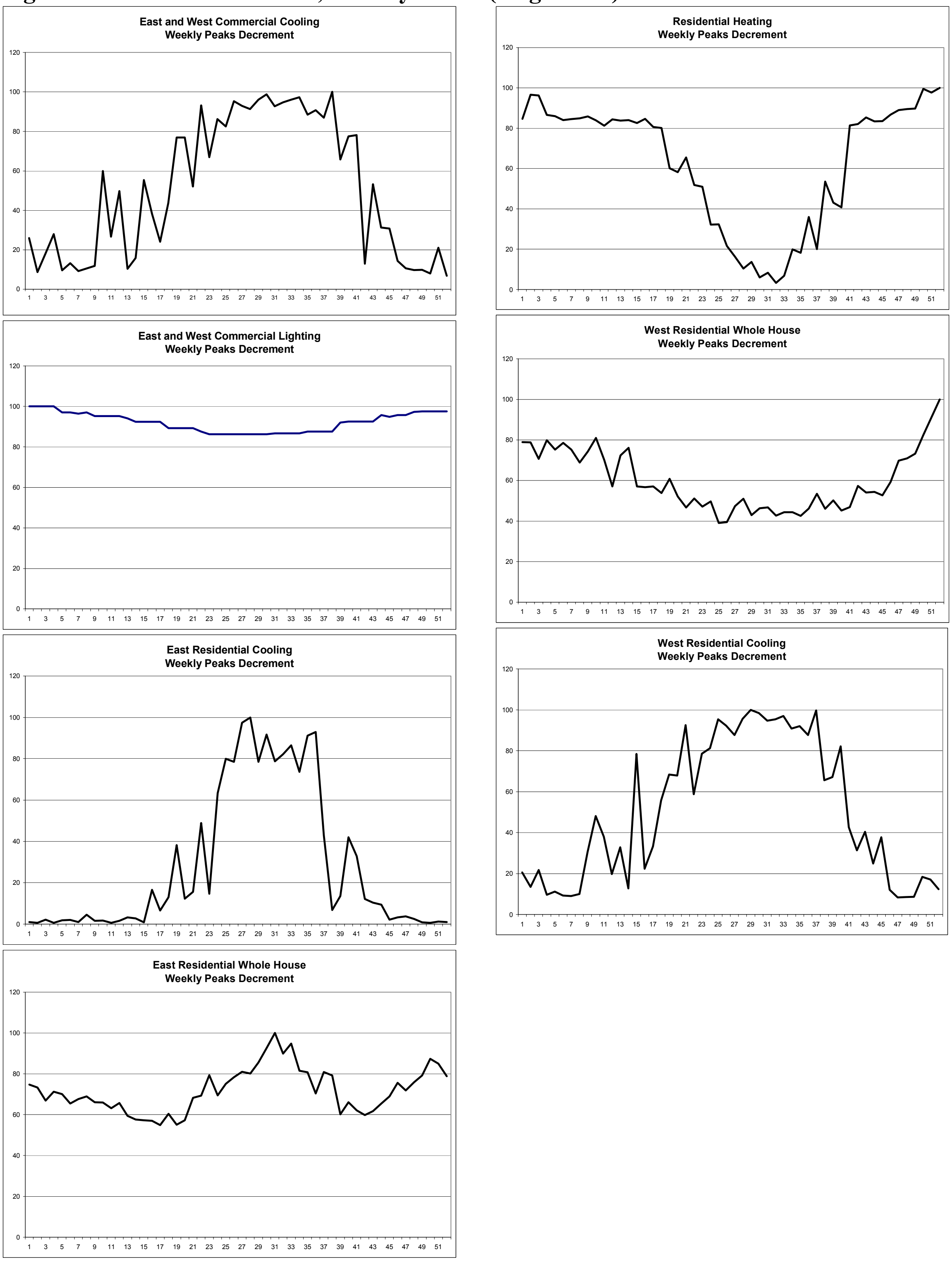


Figure 5.3 – DSM Decrement, Weekly Peaks (megawatts)[35]



[35] Weekly residential lighting peaks are constant throughout the year, though the daily timing of the peak can vary with the season.

Class 3 Demand-side Management

Tables 5.9 and 5.10 summarize the key attributes for three DSM Class 3 program subcategories (curtailable rates, critical peak pricing and demand buyback) for the west and east control area respectively. Attributes are provided for three scenarios: low, base, and high achievable potential. These scenarios reflect PacifiCorp assumed on-peak electricity market prices of $40/MWh, $60/MWh, and $100/MWh respectively, as well as incrementally higher marketing efforts, program costs, and customer participation levels. Appendix B provides more information on how the Class 3 DSM attributes were derived.

Table 5.9 – Class 3 DSM Program Attributes, West Control Area

Attributes	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	4	4	10
Start Year	2009	2009	2009
BASE			
Total Achievable Potential -- Maximum (MW)	21	3	8
Resource Costs ($/kW/yr)	$ 50	$ 56	$ 14
LOW			
Total Achievable Potential -- Maximum (MW)	9	0	3
Resource Costs ($/kW/yr)	$ 39	$ 136	$ 14
HIGH			
Total Achievable Potential -- Maximum (MW)	26	5	18
Resource Costs ($/kW/yr)	$ 86	$ 48	$ 19
Hours Available by Month			
January	-	-	-
February	-	-	-
March	-	-	-
April	-	-	-
May	-	-	-
June	-	-	-
July	69	69	129
August	18	18	46
September	-	-	-
October	-	-	-
November	-	-	-
December	-	-	-

Table 5.10 – Class 3 DSM Program Attributes, East Control Area

Attributes	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	4	4	10
Start Year	2009	2009	2009
BASE			
Total Achievable Potential -- Maximum (MW)	51	5	19
Resource Costs ($/kW/yr)	$ 50	$ 40	$ 14
LOW			
Total Achievable Potential -- Maximum (MW)	22	1	6
Resource Costs ($/kW/yr)	$ 38	$ 89	$ 13
HIGH			
Total Achievable Potential -- Maximum (MW)	63	9	46
Resource Costs ($/kW/yr)	$ 86	$ 36	$ 18
Hours Available by Month			
January	-	-	-
February	-	-	-
March	-	-	-
April	-	-	-
May	-	-	-
June	-	-	-
July	69	69	129
August	18	18	46
September	-	-	-
October	-	-	-
November	-	-	-
December	-	-	-

Resource Descriptions

Class 1 Demand-side Management

Class 1 programs are divided into two types: fully-dispatchable and scheduled-firm. Often referred to as direct load control (DLC), fully-dispatchable programs are designed to reduce the demand during peak periods by turning off equipment or limiting the "cycle" time (i.e., frequency and duration of periods when the equipment is in operation) during system peak. The offerings for the residential sector are seasonally divided, while the potential with large commercial and industrial customers typically focus on summer cooling loads only. PacifiCorp's fully-dispatchable resource options are as follows:

- **Winter –** Direct load control of water and space heating during winter are the program options considered in this class. This program would be dispatched during the morning and evening peak hours. The largest potential for such a program will be in the west control area because of the higher saturation of electric space and water heating. Incentives are generally paid on a monthly basis. Although there are no large scale DLC programs in the Northwest, Portland General Electric (PGE) and Puget Sound Energy (PSE) have both studied implementation through pilot programs. Nationally, there are many utilities with space and/or water heating controls, including Duke Power, Wisconsin Power and Light, Great River Energy, and Alliant Energy.

- **Summer –** The main demand reduction (DR) product in this group is direct load control of air-conditioning units, which are typically dispatched during the hottest summer days, and are common place due to the relatively high summer loads in warm climates. PacifiCorp currently pays monthly incentives to residential and small commercial participants in Utah's Cool Keeper AC Load Control program. There is approximately 130 megawatts of connected load for this program, which is expected to increase to 180 megawatt by summer 2007. Using a 50% cycling dispatch strategy, approximately half can be expected during an event. In addition to those utilities listed above, Nevada Power, Florida Power and Light, Alliant Energy, MidAmerican Energy and the major utilities in California run air conditioner direct load control programs (e.g., Sacramento Municipal Utility District and San Diego Gas and Electric).

- **Large Commercial and Industrial –** Direct control of large commercial and industrial (C&I) customers requires coordination with the existing energy management systems (EMS). The focus of this program type is adjustment of the HVAC equipment during the top summer hours. Incentives are generally paid on a per-kW or per-ton (of cooling equipment) basis. Some utilities running comparable programs include Florida Light & Power, Hawaiian Electric, and Southern California Edison.

Scheduled-firm program strategies are those that provide consistent reductions during pre-specified hours, and target customers with usage patterns and technology that allow scheduled shifting of consumption from peak to off-peak periods. These program strategies include the following:

- **Irrigation Pumping –** Irrigation load control is a candidate for summer DR due to the relatively low load factor (approximately 30%) of pumping equipment and the coincidence of these loads with system summer peak. Through PacifiCorp's irrigation load control program, customers subscribe in advance for specific days and hours when their irrigation systems will be turned off. Load curtailment is executed automatically based on a pre-determined schedule through a timer device. Although a total of 100 megawatts is contracted with this program, only half is available due to the alternating schedules of program participants. In the Northwest, Bonneville Power Authority (BPA) has run a pilot irrigation program (on a dispatch, rather than scheduled, basis) and Idaho Power has a program similar to that of PacifiCorp.

- **Thermal Energy Storage –** For small commercial and industrial customers, it is possible to have thermal energy storage (TES) cooling systems that produce ice during off-peak periods, which is then used during the on-peak period to cool the building. The system is programmed to use ice-cooling during pre-specified times (typically six hours per day, from April to October) and participants are given incentives on a per-kW or per-ton-of-cooling basis.

Class 2 Demand-side Management
Class 2 DSM programs are not modeled in the 2007 IRP as resource options; rather, these are handled as a decrement to the load forecast. Appendix A provides descriptions of PacifiCorp's current Class 2 programs.

Class 3 Demand-side Management
Curtailable rate options have been offered by many utilities in the United States for many years. These programs are designed to ease system peak by requiring that customers shed load by a set amount or to a set level (such as by turning off equipment or relying more heavily on on-site generation) when requested by the utility. Participants are either provided with a fixed rate discount or variable incentives, depending on load reduction; penalties are often levied for participants who do not respond to curtailment events. Large commercial and industrial customers are the target market for those programs that address PacifiCorp's summer system peak. Many utilities provide a broad range of program options, including Duke Power, Georgia Power, Dominion Virginia Power, Pacific Gas and Electric, Consolidated Edison, Southern California Edison, MidAmerican Energy Company, and Wisconsin Power and Light.

Critical peak pricing (CPP) rates only take effect a limited number of times during the year. In times of emergency or high market prices, the utility can invoke a critical peak event, where customers are notified and rates become much higher than normal, encouraging customers to shed or shift load. Typically, the CPP rate is bundled with a time-of-use rate schedule, whereby customers are given a lower off-peak rate as an incentive to participate in the program. Customers in all customer classes (residential, commercial, and industrial) may choose to participate in a CPP program, although there are certain segments in the commercial sector that are less able to react to critical peak pricing signals. Currently, there are no CPP programs being offered by Northwest utilities. Peak pricing is, however, being offered through experimental pilots or full-scale programs by several organizations in the United States, notably Southern Company (Georgia Power), Gulf Power, Niagara Mohawk, California utilities (SCE, PG&E, SDG&E), PJM Interconnection, and New York ISO (NYISO). Adoption of CPP has not been as widespread in the Western states as they have in the East. In the Pacific Northwest, this may be partly explained by the generally milder climate and the fact that, due mainly to large hydroelectric resources, energy, rather than capacity, tends to be the constraining factor.

Demand buyback/bidding (DBB) products are designed to encourage customers to curtail loads during system emergencies or high price periods. Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for the energy reduced during each event, based primarily on the difference between market prices and the utility rates. Since 2001, all major investor-owned utilities in the Northwest and Bonneville Power Administration have offered variants of this option. PacifiCorp's current program, Energy Exchange, was used extensively during 2001 and resulted in maximum reduction of slightly over 40 megawatts in that period. Demand reductions from PacifiCorp's current program are approximately 1 megawatt. Demand buyback products are common in the United States and are being offered by many major utilities. The use of DBB offerings as a means of mitigating price volatility in power markets is especially common among independent system operators including CAISO, NYISO, PJM, and ISO-NE. However, DBB options are not currently being exercised regularly due to relatively low power prices.

TRANSMISSION RESOURCES

Resource Selection Criteria

PacifiCorp developed its transmission resource options to support new generation options included in the IRP models, to enhance transfer capacity and reliability across PacifiCorp's system, and to boost import/export capability with respect to external markets. These options included transmission projects targeted for investigation as part of the MEHC acquisition commitments. (See Chapter 2, "MidAmerican Energy Holdings Company IRP Commitments.")

Resource Options and Attributes

Transmission options developed for portfolio analysis are shown in Table 5.11.[36] The column labeled "Point A" indicates one end of the transmission path, and "Point B" the other end. The maximum capacity associated with moving generation from one end to the other is shown in the subsequent columns. For resource optimization modeling, the CEM was allowed to phase in transmission purchases in 500 megawatts blocks as needed for four of the transmission paths: Bridger East-Ben Lomond (4); Mona-Utah North (5); Wyoming-Bridger East (8); and Utah North-West Main (9). Included in all portfolios is the MidAmerican Energy Holdings Company commitment (34a) for the 300 megawatt Path C upgrade assumed to be available in 2010. The transmission options as represented in the model topology are shown in Figure 5.4.

Table 5.11 – Transmission Options

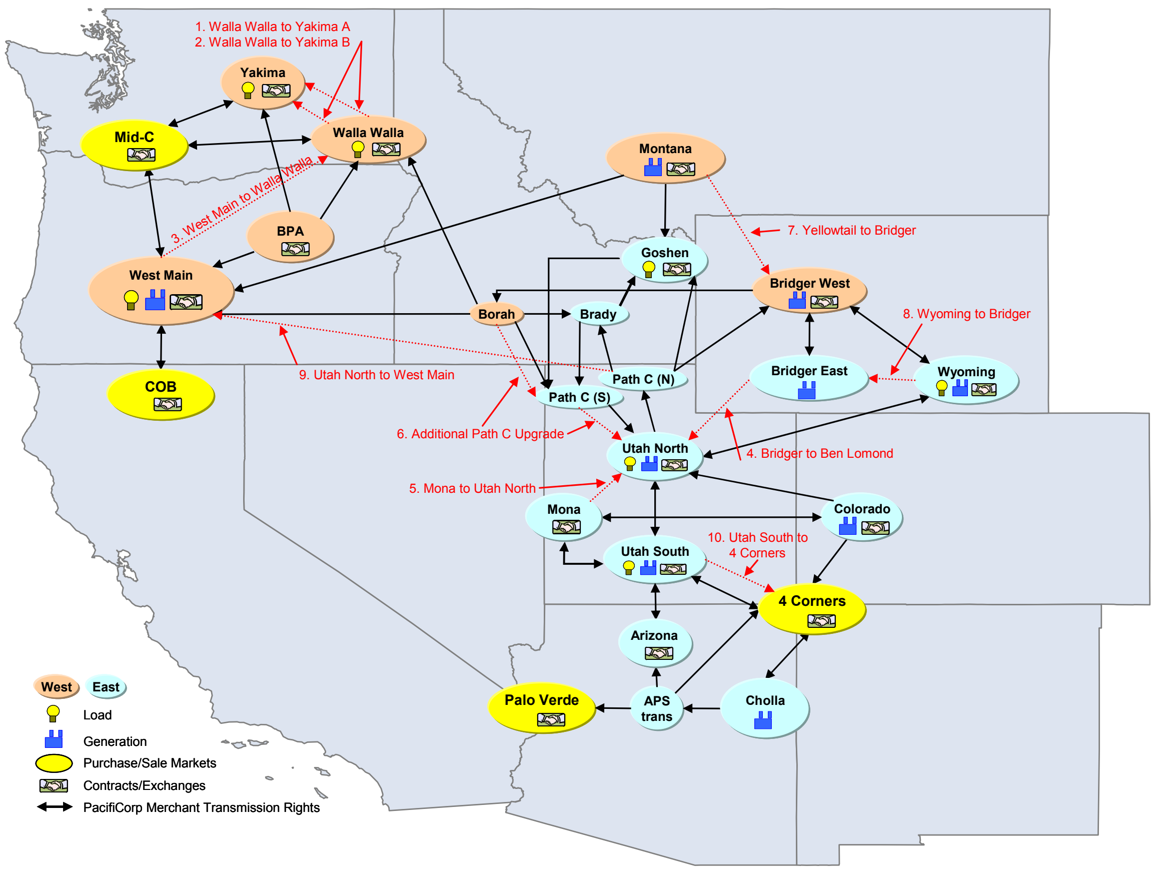
No.	Point A	Point B	A to B Capacity (MW)	B to A Capacity (MW)	First Year Available	Number of Additions
1	Walla Walla	Yakima A	630	0	2010	1
2	Walla Walla	Yakima B	400	400	2010	1
3	West Main	Walla Walla	630	0	2010	1
4	Jim Bridger East	Ben Lomond	500	0	2012	4
5	Mona	Utah North	500	0	2012	2
6	Path C – South	Utah North	600	0	2011	1
7	Yellowtail	Jim Bridger	400	0	2011	1
8	Wyoming	Jim Bridger East	500	500	2012	3
9	Utah North	West Main	500	500	2012	6
10	Utah South	Desert Southwest (includes Mona-Oquirrh)	600	600	2012	1
Base Transmission Assumptions – For All Portfolios						
11	Path C – South	Utah North	300	0	2010	1
12	Craig-Hayden	Park City	176	0	2010	1

[36] The 2007 integrated resource plan used proxy transmission additions for portfolio planning purposes. The timing and cost of these proxy additions are based on high level planning estimates which are subject to change as more information becomes available. The company may address specific transmission needs by entering into new wheeling contracts, building additional facilities, or participating in joint transmission projects.

Transmission requirements associated specifically with wind resources located in southwest Wyoming, southeast Wyoming, and eastern Nevada were not modeled as transmission paths within the CEM. The transmission costs associated with those resources were included in the capital costs of the wind resources themselves, with the generation modeled as occurring (as delivered) in Utah North for the southwest Wyoming wind; Jim Bridger East for the southeastern Wyoming wind; and Utah South for the eastern Nevada wind.

In addition to these resource options, PacifiCorp also modeled a regional transmission project for sensitivity analysis using the Capacity Expansion Module. This resource serves as a proxy for projects like the proposed Frontier Project that links generation in Wyoming with load centers in Utah, Nevada and California. See Chapter 6, "Scenario and Sensitivity Study Development", for more details on how this regional transmission resource was modeled.

Figure 5.4 – Transmission Options Topology



MARKET PURCHASES

<u>Resource Selection Criteria</u>

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the

IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). Front office transactions are proxy resources, assumed to be firm, that represent procurement activity expected to be made on an annual forward basis to help the company cover short positions.

For this IRP, PacifiCorp tested portfolios that included a limit of 1,200 megawatts of front office transactions beyond 2011. Table 5.12 shows the maximum capacity available for the four market hubs in cases where front office transactions limits were applied.

Table 5.12 – Maximum Available Front Office Transaction Quantities by Market Hub

Market Hub	Maximum Available Capacity (MW)
West Main	250
Mid Columbia	250
Four Corners	500
Mona	200
TOTAL	**1,200**

To arrive at these maximum quantities, PacifiCorp considered the following:

- Historical operational data and institutional experience with transactions at the market hubs.
- The company's forward market view, including an assessment of expected physical delivery constraints and market liquidity and depth.
- Financial and risk management consequences associated with acquiring purchases at higher levels, such as additional credit and liquidity costs.

Resource Options and Attributes

Two front office transaction types were included for portfolio analysis: a west-side annual flat product, and an east-side heavy load hour (HLH) 3rd quarter product. The west-side transaction reflects purchases of flat annual energy—a constant delivery rate over all the hours of a year—delivered to the West Main bubble.[37] The east-side transactions are represented as heavy load hour (16 hours per day, 6 days per week) purchases from July through September available for delivery at both the Mona and Four Corners market hubs. Because these products are assumed to be firm for this IRP, the capacity contribution of front office transactions is grossed up for purposes of meeting the planning reserve margin. For example, a 100 megawatt front office transaction is treated as a 112 megawatt contribution to meeting a 12 percent planning reserve margin, with the selling counterparty holding the reserves necessary to make the product firm.

Prices for front office transaction purchases are associated with specific market hubs—Mid-Columbia (Mid-C), Mona, and Four Corners—and are set to the relevant forward market prices for the relevant time period and location.

[37] A bubble refers to a distinct area of a system model's network topology encompassing one or a combination of the following attributes: load, generation, markets (purchases and sales), and transmission facilities. A bubble is also referred to as a transmission area.

Resource Description

As proxy resources, front office transactions represent a range of purchase transaction types. They are usually standard products, such as heavy load hour (HLH), light load hour (LLH), and/or daily HLH call options (the right to buy or "call" energy at a "strike" price) and typically rely on standard enabling agreements as a contracting vehicle. Front office transaction prices are determined at the time of the transaction, usually via a third party broker and based on the view of each respective party regarding the then-current forward market price for power. An optimal mix of these purchases would include a range in terms for these transactions.

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

Proposed Use and Impact of Physical and Financial Hedging

The company proposes to continue to hedge the price risk inherently carried due to volume mismatches between sales obligations and economic resources by purchasing or selling fixed-price energy in the forward market. The purpose of these transactions is to mitigate the company's financial exposure to the short term markets, which historically have much greater price volatility than the longer term markets. Specifically, purchasing to cover a short position in the forward market reduces the company's financial exposure to increasing prices, albeit these transactions also reduce the company's financial opportunity if prices decrease. Selling to cover a long position has a similar effect.

The company proposes to continue to hedge its electricity and natural gas fixed-price exposure using both physical products and financial products. Both products are effective in hedging this exposure.

6. MODELING AND RISK ANALYSIS APPROACH

Chapter Highlights

- The IRP modeling effort seeks to determine the comparative cost, risk, supply reliability, and emissions attributes of resource portfolios.

- The 2007 IRP modeling effort consisted of three phases: (1) resource screening using the company's capacity expansion optimization tool (the Capacity Expansion Module, or CEM), (2) risk analysis portfolio development, and (3) detailed probabilistic (stochastic) production cost simulation and resource risk analysis.

- For resource screening, PacifiCorp defined 16 alternative future scenarios and associated sensitivity studies with the assistance of public stakeholders. These alternative futures test wide variations in potential CO_2 regulatory costs, natural gas prices, wholesale electricity prices, retail load growth, and the scope of renewable portfolio standards.

- In addition, the company defined futures to evaluate the availability of renewable production tax credits and the level of achievable market potential for load control and demand-response programs.

- PacifiCorp next defined risk analysis portfolios for stochastic simulation. The CEM was used to help build fixed resource investment schedules for wind and distributed resources, and to optimize the selection of other resource options according to specific resource strategies.

- PacifiCorp devoted considerable effort to model the effect of CO_2 emission compliance strategies. All risk analysis portfolios were simulated with five CO_2 adder levels—$0/ton, $8/ton, $15/ton, $38/ton, and $61/ton (in 2008 dollars)—and associated forward gas/electricity price forecasts. The company modeled both a cap-and-trade and emissions tax compliance strategy, and expanded its reporting of CO_2 emissions impacts.

- Portfolio performance was assessed with the following measures: (1) stochastic mean cost (Present Value of Revenue Requirements), (2) customer rate impact, measured as the levelized net present value of the change in the system average customer price due to new resources for 2008 through 2026, (3) emissions externality cost, (4) capital cost, (5) risk exposure, (6) CO_2 and other emissions, (7) and supply reliability statistics.

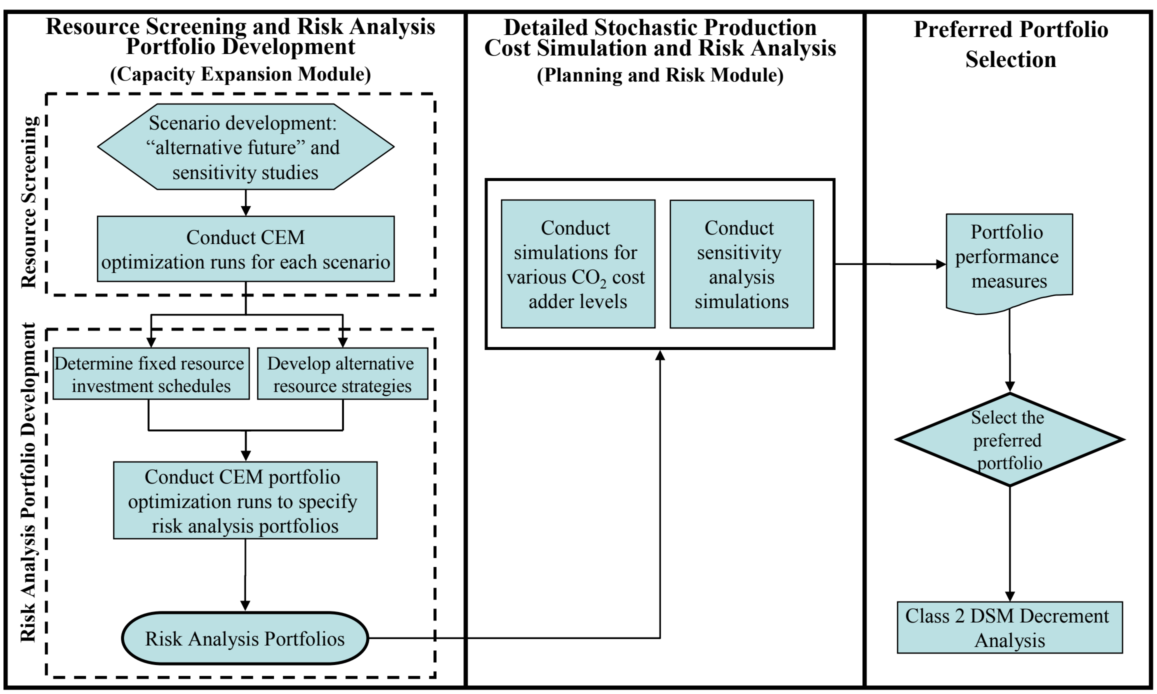
- The preferred portfolio is selected from among the risk analysis portfolios primarily on the basis of relative cost-effectiveness, customer rate impact, and cost/risk balance across the CO_2 adder levels.

INTRODUCTION

The IRP modeling effort seeks to determine the comparative cost, risk, reliability, and pollutant emissions attributes of resource portfolios. These portfolio attributes form the basis of an overall portfolio performance evaluation. This chapter describes the modeling and risk analysis process that supported portfolio performance evaluation. The information drawn from this process, summarized in Chapter 7, was used to help determine PacifiCorp's preferred portfolio.

The 2007 IRP modeling effort consists of three phases: (1) resource screening, (2) risk analysis portfolio development, and (3) detailed production cost and stochastic risk analysis. The Capacity Expansion Module (CEM) supports resource screening and development of risk analysis portfolios. Detailed production cost simulation and associated stochastic analysis, which attempts to quantify the most significant sources of portfolio risk, are supported by the Planning and Risk (PaR) Module. Figure 6.1 characterizes the three phases in flow chart form, showing the main steps involved and how these phases are linked with the preferred portfolio selection phase (far right on the chart). This chapter covers each of these steps.

Figure 6.1 – Modeling and Risk Analysis Process



RESOURCE SCREENING

For resource screening, PacifiCorp evaluated generation, demand-side management, market purchase, and transmission resources on a comparable basis using the Capacity Expansion Module. The CEM performs a deterministic least-cost optimization with these resources over the twenty-year study horizon. To support resource screening, the company developed a set of "alternative future" scenarios to study. These scenarios consist of combinations of input variables representing the primary sources of portfolio cost uncertainty. Additional sensitivity analysis scenarios were also developed to investigate the individual effects of certain planning and resource-specific assumptions.

The main objectives of this screening effort include the following:

- Determine and study resource selection choices given different assumptions about the future
- Determine the range of resource quantities selected for alternative future scenarios designed to favor one or more resource types over others.
- Identify the frequency of resources selected across the alternative futures modeled.
- Determine acquisition patterns (quantities and timing) for smaller-scale resource types—front office transactions, wind, DSM programs, and Combined Heat and Power facilities—to be incorporated into the risk analysis portfolios based on an aggregate view of the alternative future modeling results.

Alternative Future Scenarios

The alternative future scenarios consist of cases to test the impact of variations in load growth as well as combinations of several variable values that simulate conditions variously favorable and unfavorable to the major resource types (coal, gas, renewables, and DSM). The input variables chosen to represent the alternative futures consist of the following:

- Incremental coal cost, consisting of new CO_2 regulatory costs (via a dollar-per-ton CO_2 adder) and alternative commodity price trends driven by assumptions on coal production and transportation costs.
- Natural gas and wholesale electricity prices, based on PacifiCorp's forward price curves
- Retail load growth
- The level of renewable electricity generation requirements stemming from renewable portfolio standard (RPS) regulations
- The availability of renewable energy Production Tax Credits (PTCs) after 2007
- The potential for demand-side management programs, defined as a program's achievable market potential adjusted to account for competition with existing programs

PacifiCorp developed low, medium, and high values for each of these input variables to ensure that a reasonably wide range in potential outcomes is captured. The one exception is for renewable PTC availability, which was structured as a yes-or-no outcome.

Table 6.1 profiles the 16 alternative future scenarios developed, indicating the assigned variable value levels for each of the six input variables. Note that alternative future scenarios are labeled with the acronym "CAF", which stands for CEM alternative future. The CAF studies include a business-as-usual case reflecting no new regulatory requirements (CAF00) and a medium case based on the company's official load forecast and forward price curves (CAF11, "medium load growth"). All CAF scenarios assume a 15-percent planning reserve margin.

Table 6.1 – Alternative Future Scenarios

CAF #	Name	Coal Cost: CO_2 Adder/Coal Commodity Price	Gas/ Electric Price	Load Growth	Renewable Sales Percentage due to RPS	Renewable PTC Availability	DSM Potential
0	Business As Usual	None/Medium	Medium	Medium	Low	Yes	Medium
1	Low Cost Coal/High Cost Gas	None/Low	High	Medium	Medium	Yes	Medium
2	with Low Load Growth	None/Low	High	Low	Medium	Yes	Medium
3	with High Load Growth	None/Low	High	High	Medium	Yes	Medium
4	High Cost Coal/Low Cost Gas	High/High	Low	Medium	Medium	Yes	Medium
5	with Low Load Growth	High/High	Low	Low	Medium	Yes	Medium
6	with High Load Growth	High/High	Low	High	Medium	Yes	Medium
7	Favorable Wind Environment	High/Medium	High	Medium	High	Yes	Medium
8	Unfavorable Wind Environment	None/Medium	Low	Medium	Low	No	Medium
9	High DSM Potential	High/Medium	High	Medium	Medium	Yes	High
10	Low DSM Potential	None/Medium	Low	Medium	Medium	Yes	Low
11	Medium Load Growth	Medium/Medium	Medium	Medium	Medium	Yes	Medium
12	Low Load Growth	Medium/Medium	Medium	Low	Medium	Yes	Medium
13	High Load Growth	Medium/Medium	Medium	High	Medium	Yes	Medium
14	Low Cost Portfolio Bookend	None/Low	Low	Low	Medium	Yes	Medium
15	High Cost Portfolio Bookend	High/High	High	High	Medium	No	Medium

Variable Value Frequency Counts (Excluding "Business As Usual" Scenario)						
"High" Count	6/4	6	4	1	N/A	1
"Medium" Count	3/7	3	7	13	N/A	13
"Low" and "None" Count	6/4	6	4	1	N/A	1
TOTALS	15/15	15	15	15	N/A	15

In developing these scenarios as well as other CEM studies, PacifiCorp relied heavily on feedback from public stakeholders. An important design criterion was to ensure that the scenarios, in aggregate, were not biased towards certain resource outcomes. As indicated at the bottom of Table 6.1, the number of scenarios with low and high values for an input variable is the same. Another design criterion was to construct them so as to enable straightforward comparisons with respect to changes in variables, particularly load growth.

Table 6.2 summarizes the values and data sources for the input variables with low, medium, and high values. Additional details for each input variable follow.

Table 6.2 – Scenario Input Variable Values and Sources

Input Variable	Low Value	Medium Value	High Value
CO_2 Cost Adder	None	\$8/ton in 2008 dollars, beginning in 2010 with costs phased in at 50%, escalating to 75% in 2011 and 100% in 2012	\$37.9/ton in 2008 dollars (\$25/ton in 1990 dollars), beginning in 2010 with costs phased in at 50%, escalating to 75% in 2011 and 100% in 2012
Coal Commodity Prices for New Resources	12% lower than the PacifiCorp Fuels Marketing & Supply Group price forecast by 2026	PacifiCorp Fuels Marketing & Supply Dept. price forecast	20% higher than the PacifiCorp Fuels Marketing & Supply Group price forecasts by 2026
Natural Gas Prices	32% lower than the PacifiCorp official forward prices (dated August 3, 2006), on an average annual basis for 2007 through 2016	PacifiCorp official forward prices, dated August 31, 2006; Incorporates PIRA Energy's August 3, 2006 probabilistic-weighted long-term gas forecast	86% higher than the PacifiCorp official forward prices (dated August 3, 2006), on an average annual basis for 2007 through 2016
Wholesale Electricity Prices	14% lower than the PacifiCorp official forward prices, dated August 31, 2006, on an average annual basis for 2007 through 2016; low values reflect a \$0/ton CO_2 adder and the PIRA low Gas price forecast case	PacifiCorp official forward prices, dated August 31, 2006	25% higher than the PacifiCorp official forward prices, dated August 31, 2006, on an average annual basis for 2007 through 2016; high values reflect a \$37.7/ton CO_2 adder and the PIRA high gas price forecast case
Retail Load Growth	Average annual system-wide load growth of 0.6% for 2007 through 2026	Average annual system-wide load growth of 2.0% for 2007 through 2026 (PacifiCorp long term load forecast, May 1, 2006)	Average annual system-wide load growth of 3.6% for 2007 through 2026
Renewable Portfolio Standards	3% of system-wide retail load by 2020	6% of system-wide retail load by 2020 (Assumes California, Washington, and Oregon RPS targets in place)	15% of system-wide retail load by 2020 (Assumes RPS targets in place in all states)
Class 1 and Class 3 DSM Achievable Potential	Starting in 2009: ● 69 MW of Class 1 programs ● 40 MW of Class 3 programs	Starting in 2009: ● 153 MW of Class 1 programs ● 106 MW of Class 3 programs	Starting in 2009: ● 219 MW of Class 1 programs ● 166 MW of Class 3 programs

Carbon Dioxide Regulation Cost

For the CO_2 regulation cost, PacifiCorp sought public comments and recommendations on a suitable cost adder for its high scenario value. At the IRP public meeting held on June 7, 2006, PacifiCorp proposed \$25/ton and \$40/ton adders (in 1990 dollars). Meeting participants accepted the \$25/ton level (\$38/ton in 2008 dollars) as appropriate for reflecting the threshold at which a significant shift in resource selection would occur based on regulatory costs.

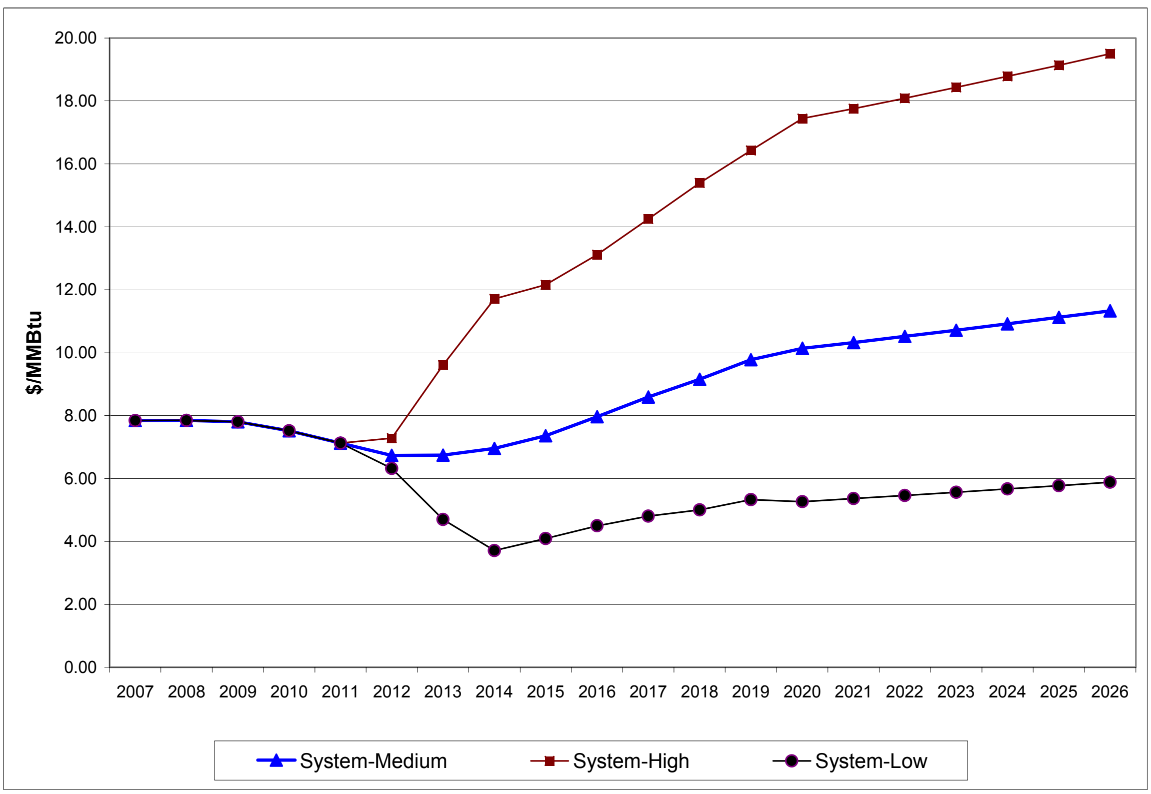
Commodity Coal Cost

Percentages for the low and high coal commodity cost values are based on the U.S. Energy Information Administration's low and high delivered coal price sensitivity forecast cases reported in the 2006 Annual Energy Outlook.[38] PacifiCorp assumed one-half of the difference between the sensitivity and reference cases to account for the fact that transportation costs, a main component of the cost forecast, are a relatively smaller portion of the delivered fuel cost in the Rocky Mountain region than for the U.S. as a whole.

Natural Gas and Electricity Prices

Due to the strong correlation between natural gas and wholesale electricity prices, these variables were linked together as low, medium, or high values for a scenario. The low and high gas price forecasts were based on PIRA Energy's Henry Hub low and high prices cases, and come from PIRA Energy's long-term gas forecast update, dated June 15, 2006. Figure 6.2 shows the system average annual low, medium, and high natural gas prices. Figure 6.3 shows the system annual average low, medium, and high electricity prices by Heavy Load Hour and Light Load Hour periods.[39]

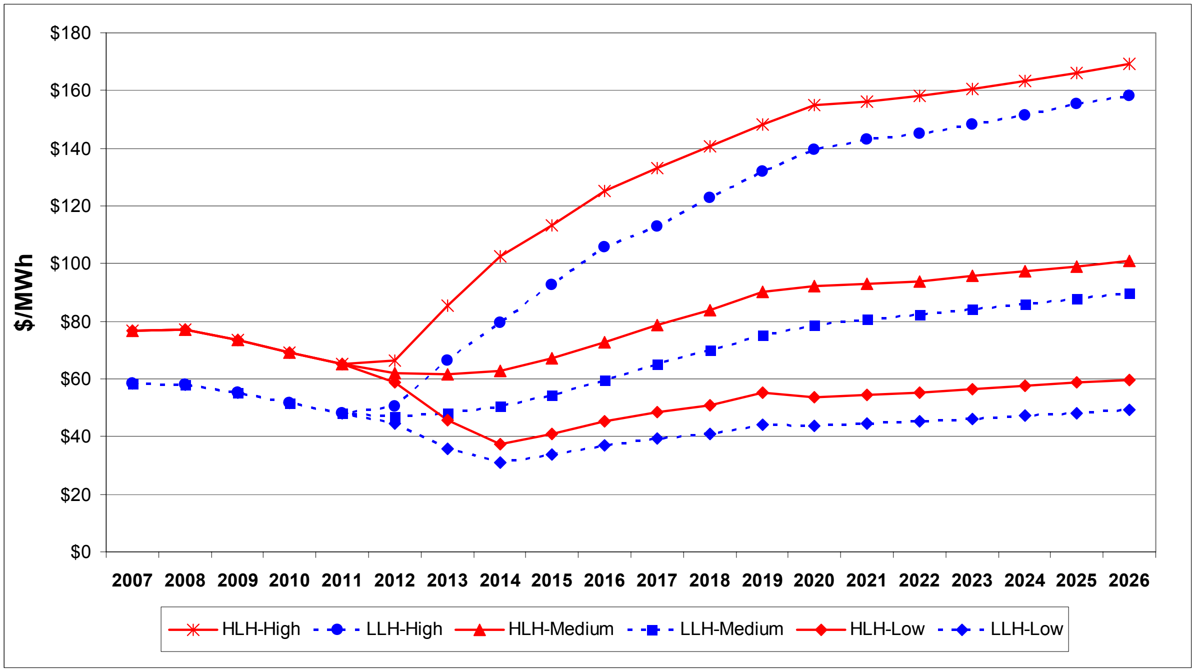
Figure 6.2 – System Average Annual Natural Gas Prices: Low, Medium, and High Scenario Values



[38] U.S. Energy Information Administration, *Annual Energy Outlook 2006 with Projections to 2030*, DOE/EIA-0383(2006), December 2005.

[39] Heavy Load Hours constitute the period from 6 a.m. to 10 p.m., Monday through Saturday. Light Load Hours are 10 p.m. to 6 a.m., Monday through Saturday, and all of Sunday and holidays.

Figure 6.3 – System Average Annual Electricity Prices for Heavy and Light Load Hour Natural Gas Prices: Low, Medium, and High Scenario Values



Retail Load Growth

The low and high load growth forecasts were determined by using the 5th and 95th percentile average load values from 100 stochastic iterations of the PaR model for 2026. Annual growth factors were applied to the medium load forecast. For the low forecast, the growth factor is the ratio of the average loads for the 5th percentile stochastic values to the load for the medium value in 2026. For the high forecast, the growth factor is the ratio of the average loads for the 95th percentile stochastic values to the load for the medium load value in 2026.

Renewable Portfolio Standards

For modeling the impact of renewable portfolio standards across the company's six-state service territory, PacifiCorp determined a system-wide annual generation requirement based on an assessment of state RPS requirements in California and Washington, and the contribution of each state to system retail sales. The system renewables generation requirement is translated into an incremental requirement by deducting renewables generation expected for 2007.

Class 1 and Class 3 DSM Potential

The development of low, medium, and high potentials for Class 1 and Class 3 demand-side management programs is described in detail in Chapter 5 and Appendix B. The Class 1 DSM programs included in the alternative future scenarios consist of dispatchable load control, scheduled irrigation, and thermal energy storage. The Class 3 programs consist of curtailable rates, critical peak pricing, and demand buyback. While the alternative future scenario studies included both Class 1 and Class 3 programs as resource options, only Class 1 resources were considered for risk analysis portfolio development. This decision was based on the need to conduct further research on the reliability of Class 3 DSM resources to address peak load demand issues, and to improve the modeling representation of the programs based on the DSM potentials study.

Sensitivity Analysis Scenarios for the Capacity Expansion Module

The Capacity Expansion Module sensitivity analysis scenarios—designated with the acronym SAS and totaling 16 in number—are intended to supplement the alternative future analysis.[40] The focus of these scenarios is to determine optimal portfolios resulting from changes to secondary variables and other resource selection factors, with the results to be compared to those for a reference scenario. These sensitivity scenarios are defined with the primary variable values specified for the "Medium Load Growth" scenario (CAF11) except where noted below. The CEM sensitivity scenarios, which are listed in Table 6.3, test the following conditions:

- Alternative capacity Planning Reserve Margin levels – low (12%) and high (18%) values.
- Deferred carbon dioxide adder implementation – CO_2 costs start accruing in 2016 as opposed to 2012, which is the assumed year of a fully phased-in CO_2 adder.
- The impact of a regional transmission project – The regional transmission option consists of a new 1,500-megawatt line from Wyoming to the SP15 transmission zone in southern California, and a new 1,500-megawatt line from Utah to the NP15 transmission zone in northern California. (The CEM was not allowed to choose this resource; rather, it was fixed in order to determine the economic benefits assuming that it is built and PacifiCorp acquires an ownership share or transmission rights.)
- Determination of the carbon dioxide adder threshold value that affects resource selection; specifically, run the CEM with incrementally higher CO_2 adders to determine at what point major changes in resource selection are made.
- Low and high wind project capital costs (see Table 6.4)
- Low and high coal commodity prices
- Low and high IGCC plant capital costs (see Table 6.4)
- Integrated Gasification Combined Cycle technology configurations – constrain the Capacity Expansion Module to select an IGCC plant if not chosen as a resource given expected values for the primary variables (i.e., the "Medium Load Growth", CAF11). The IGCC plant is tested with three configurations: minimum carbon capture provisions, one gasifier, and carbon sequestration included. The scenarios are used to determine the incremental cost impact relative to an unconstrained resource choice.
- An alternative approach for determining the peak system obligation[41]
- Impact of renewable Production Tax Credit expiration combined with other regulatory developments favorable for wind projects, namely CO_2 regulation and widely-adopted renewable portfolio standards. This scenario uses variable values defined for the "favorable wind environment" alternative future scenario (CAF07).

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[40] A sensitivity scenario for testing the impact of replacing Klamath Falls hydro units with alternative resources was excluded from the list, as it was determined that such analysis was not appropriate for the IRP setting given ongoing litigation and settlement discussions.

[41] In its 2004 IRP Acknowledgement Order, the Oregon Public Utility Commission directed PacifiCorp to "evaluate alternatives for determining the expected annual peak demand for determining the planning margin—for example, planning to the average of the eight-hour super-peak period." (Order No. 06-029, January 23, 2006.)

Table 6.3 – Sensitivity Scenarios

SAS#	Name	Basis
1	Plan to 12% planning reserve margin	Alternative Futures Scenario #11 ("Medium Load Growth")
2	Plan to 18% planning reserve margin	Alternative Futures Scenario #11 ("Medium Load Growth")
3	CO_2 adder implementation in 2016	Alternative Futures Scenario #11 ("Medium Load Growth")
4	Regional transmission project	Alternative Futures Scenario #11 ("Medium Load Growth")
5-10 5-15 5-20	CO_2 adder impact on resource selection: test \$15, \$20, \$25 per ton adders (approximately \$10, \$15, and \$20 in 1990 dollars)	Alternative Futures Scenario #11 ("Medium Load Growth")
6	Low wind capital cost	Alternative Futures Scenario #11 ("Medium Load Growth")
7	High wind capital cost	Alternative Futures Scenario #11 ("Medium Load Growth")
8	Low coal price	Alternative Futures Scenario #11 ("Medium Load Growth")
9	High coal price	Alternative Futures Scenario #11 ("Medium Load Growth")
10	Low IGCC capital cost	Alternative Futures Scenario #11 ("Medium Load Growth")
11	High IGCC capital cost	Alternative Futures Scenario #11 ("Medium Load Growth")
12	Add a carbon-capture-ready IGCC to the portfolio (base case for SAS13 and SAS14)	Alternative Futures Scenario #11 ("Medium Load Growth")
13	Replace the IGCC resource in the SAS12 portfolio with a single-gasifier version	SAS #12
14	Replace the IGCC resource in the SAS12 portfolio with one that includes carbon sequestration	SAS #12
15	Plan to "average of super-peak" load	Alternative Futures Scenario #11 ("Medium Load Growth")
16	"Favorable Wind Environment" scenario assuming permanent expiration of the renewables PTC beginning in 2008	Alternative Futures Scenario #07 ("Favorable Wind Environment")

Table 6.4 – CEM Sensitivity Scenario Capital Cost Values

Input Variable	Low Value	Medium Value	High Value
IGCC Capital Cost	5% lower than the PacifiCorp Resource Development and Construction Dept. cost estimates	Based on a configuration with minimum carbon capture preparation and Level II emission controls. PacifiCorp Resource Development and Construction Dept. cost estimates	12.5% higher than the PacifiCorp Resource Development and Construction Dept. cost estimates
Wind Capital Cost	10% lower than the PacifiCorp Resource Development and Construction Dept. cost estimates	Based on PacifiCorp Resource Development and Construction Dept. cost estimates	11% higher than the PacifiCorp Resource Development and Construction Dept. cost estimates

Sensitivity Analysis Scenarios for the Planning and Risk Module

A number of stochastic simulations were performed for sensitivity analysis purposes. Several of the scenarios were designed to address specific risk analysis requirements identified in the Oregon Public Utility Commission's Integrated Resource Planning guidelines and 2004 IRP acknowledgement order. The Planning and Risk Module sensitivity scenarios test the following conditions:

- Plan to a 12% planning reserve margin, and include a sufficient amount of Class 3 demand-side management program capacity to eliminate Energy Not Served (ENS).[42] This study addresses an Oregon Public Utility Commission acknowledgement order requirement.
- Plan to an 18% planning reserve margin – use the same portfolio resources selected by the Capacity Expansion Module for Sensitivity Analysis Scenario #2 ("Plan to 18% capacity reserve margin")
- Using one of the risk analysis portfolios as the basis, replace a new base load resource with an equivalent amount of front office transactions to determine the incremental cost and risk impacts.
- Using one of the risk analysis portfolios as the basis, replace a base load pulverized coal resource with an IGCC plant that has minimum carbon capture provisions. Also include sufficient shorter-term resources to maintain the planning reserve margin until an IGCC plant can be placed into service.
- Using one of the risk analysis portfolios as the basis, replace a new resource with Combined Heat & Power (CHP) and aggregated dispatchable customer-owned standby generators to determine the incremental cost and risk impacts.[43] This sensitivity addresses an analysis requirement in the Oregon Public Utility Commission's 2004 Integrated Resource Plan acknowledgement order.

Capacity Expansion Module Optimization Runs

The Capacity Expansion Module is executed for each alternative future and sensitivity scenario, generating an optimized investment plan and associated real levelized present value of revenue requirements (PVRR) for 2007 through 2026. To avoid bunching of coal-fired resources at the end of the 10-year investment period when higher variable cost CCCT growth stations become available, a two-year investment extension period is added to enable the model to select all resource options through 2018.[44]

[42] Energy Not Served is a condition due to physical or market constraints where insufficient energy is available to meet load obligations.

[43] Large industrial sector CHP was included as a resource option in the CEM scenarios. For this sensitivity scenario, proxy resources representing small-to-medium sized industrial CHP plants (5 and 25 MW) were included along with a resource representing aggregate standby generators. For standby generators, PacifiCorp used Portland General Electric Company's standby generator program as the basis for determining resource characteristics. Due to air quality issues in Utah, standby generators were only modeled as a west-side resource.

[44] Growth stations are included as a generic resource choice beginning in 2019 to address load growth, plant retirements, and contract expirations during the out-years of the study period. Optimizing with a single resource for part of the study period is a necessary compromise for maintaining acceptable model run-times.

The CEM operates by minimizing for each year the operating costs for existing resources subject to system load balance, reliability and other constraints. Over the 20-year study period, it also optimizes resource additions subject to resource investment and capacity constraints (monthly peak loads plus a planning reserve margin for the 24-zone model topology).

To accomplish these optimization objectives, the model performs a time-of-day least-cost dispatch for existing and potential planned generation, contract, demand-side management, and transmission resources. The dispatch is based on a representative-week method. Time-of-day hourly blocks are simulated according to a user-specified day-type pattern representing an entire week. Each month is represented by one week, with results scaled to the number of days in the month and then the number of months in the year. The dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the overall PVRR, consisting of the net present value of contract and spot market purchase costs, generation costs (fuel, fixed and variable operation and maintenance, unserved energy, and unmet capacity), and amortized capital costs for planned resources.

For capital cost derivation, the CEM uses annual capital recovery factors to address end-effects issues associated with capital-intensive investments of different durations and in-service dates. PacifiCorp used the real-levelized capital costs produced by the CEM for PVRR reporting by both the CEM and Planning and Risk module.

Modeling Front Office Transactions

Front office transactions, described in Chapter 5, are assumed to be transacted on a one-year basis, and are represented as available in each year of the study. For capacity optimization modeling, the CEM engages in market purchase acquisition—both front office transactions and spot market purchases—to the extent it is economic given other available resources. The model can select virtually any quantity of FOT generation up to limits imposed for each scenario, in any study year, independently of choices in other years. However, once a front office transaction resource is selected, it is treated as a must-run resource for the duration of the transaction. In addition, front office transactions are only available through 2018. After 2018, the purchases are set to zero, at which point the model can select "growth stations."

The transactions modeled in the Planning and Risk Module generally have the same characteristics as those modeled in the CEM, except that transaction prices reflect wholesale forward electric market prices that are "shocked" according to a stochastic modeling process prior to simulation execution.

RISK ANALYSIS PORTFOLIO DEVELOPMENT

Risk analysis portfolios refer to portfolio solutions, obtained from one or more CEM runs, which are subjected to stochastic production cost simulation using the Planning and Risk module. To develop the risk analysis portfolios, PacifiCorp relied on the CEM to build fixed resource investment schedules for wind and distributed resources, and to optimize the selection of other resource options according to specific resource strategies defined as constraints on the model solution. For example, a resource strategy may entail restricting the range of resource choices, placing constraints on when resources can be selected, or implementing upper limits on resource quantities. The impact of evolving state regulatory policies was considered in developing resource constraints.

Determination of Fixed Resource Investment Schedules

PacifiCorp used the CEM to determine fixed resource investment schedules for certain smaller-scale resource types—wind, demand-side management programs and CHP facilities—in order to limit resource variability for subsequent CEM optimization studies and in the risk analysis portfolios themselves. (Restricting the number of resources is important for managing portfolio analysis complexity and model run-times.[45]) These investment schedules constitute set resource quantities, locations, and in-service dates that are included in all risk analysis portfolios. In the case of the proxy wind resources, PacifiCorp developed multiple fixed investment schedules for portfolio testing. For DSM and CHP a single investment schedule was developed and used in the risk analysis portfolios.

The company determined most of the fixed resource investment schedules by assessing the CEM's resource selection behavior across the range of alternative future scenarios described above. The next chapter describes the investment schedules derived from the alternative future scenario analysis.

Alternative Resource Strategies

PacifiCorp's resource strategies fall into two categories: (1) those intended to evaluate the impacts of incremental resource changes, and (2) those intended to evaluate a specific resource investment policy. Strategies that fall into the first category typically involve specifying model constraints around a single resource, such as forcing selection for a certain year or removing it altogether as an option. The second category encompasses strategies that broadly tackle certain portfolio risks. Such risks include CO_2 regulatory costs, escalation and volatility of wholesale electricity and natural gas prices, and potential state restrictions and standards for resource acquisition (e.g., renewable portfolio standards). Examples of such resource strategies include eliminating or deferring an entire resource type such as coal, gas, or market purchases.

Optimization Runs for Risk Analysis Portfolio Development

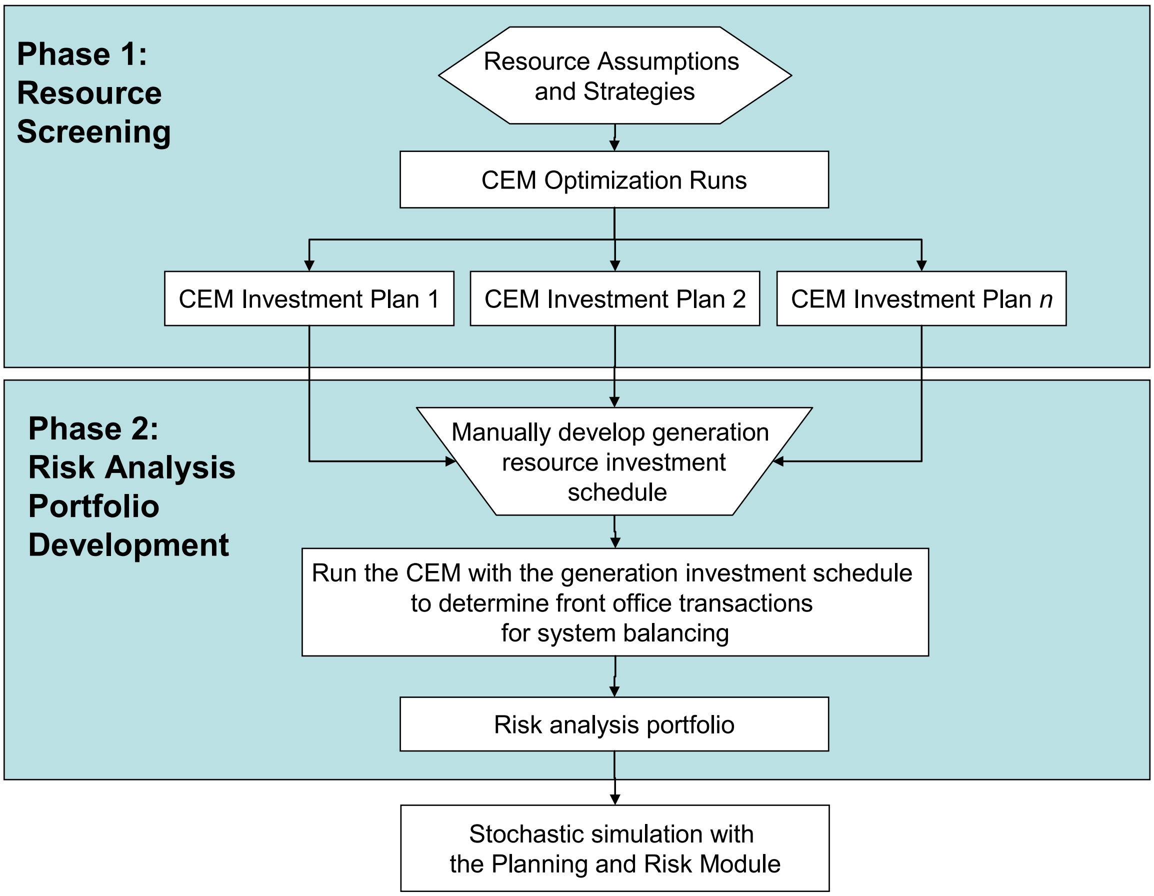
The CEM is ready for execution once the fixed resource investment schedules and resource strategies have been defined and input into the model. All CEM runs are configured as "Mixed Integer Programming" problems. This means that expansion choices can be represented as either build/not-build binary variables or continuous variables that enable the model to select fractional resource amounts. The mixed integer solution better characterizes investments where large fixed capital costs are involved.

In certain cases, a single CEM run completely defines the portfolio that is to be simulated using PaR. In other cases, a group of CEM runs are used to test multiple resource strategies or assumptions. For this later situation, PacifiCorp manually selects the resource investment schedule based on observations across the set of CEM runs. This approach is typically used to determine the model's selection behavior for a specific resource when other resources are constrained in differ-

[45] A limitation of this modeling strategy is that variable amounts of DSM and CHP resources were not subjected to risk analysis using the PaR model. PacifiCorp will continue to refine its approach to modeling distributed resources in concert with the scheduled June 2007 receipt of DSM and CHP supply curve data from the multi-state DSM potentials study.

ent ways. A resource that is routinely selected or chosen for a certain year indicates a robust resource under the set of simulated resource strategies. The CEM is then executed a second time with this fixed set of generation resources. The purpose of this additional run is to have the CEM optimize the selection of remaining available resource options, thereby ensuring that the final portfolio meets the model's planning reserve margin constraints. This two-step process is summarized in Figure 6.4.

Figure 6.4 – Two-Stage Risk Analysis Portfolio Development Process



STOCHASTIC SIMULATION OF RISK ANALYSIS PORTFOLIOS

Stochastic Risk Analysis

PacifiCorp next simulates each risk analysis portfolio, along with existing system resources, using the Planning and Risk model in stochastics mode. The PaR simulation produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The PaR simulation also incorporates stochastic risk in its production cost estimates by using Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability.[46]

[46] Although wind resource generation was not varied in the same way as the other stochastic variables, the hour-to-hour generation did vary throughout the year, but the pattern was repeated identically for all study years (2007-2026) and iterations (1-100).

A stochastic model in PaR guides the random sampling process. The stochastic model accounts for both short-term and long-term variable volatility as well as correlation effects among the variables. (Appendix E describes PacifiCorp's stochastic modeling methodology.) The output of the stochastic model consists of stochastic parameters—multipliers that represent the stochastic "shocks" applied to the expected value forecasts for each variable.

The PaR model is configured to conduct 100 Monte Carlo simulations for the 20-year study period, so that each of the 100 simulations has its own set of stochastic parameters and shocked forecast values. The end result of the Monte Carlo simulation is 100 production cost runs (iterations) reflecting a wide range of alternative futures. PacifiCorp derives expected values for the Monte Carlo simulation by averaging run results across all 100 iterations.

The company also looks at subsets of the 100 iterations that signify particularly adverse cost conditions, and derives associated cost measures as indicators of high-end portfolio risk, or "risk exposure." The company uses scatter plots of portfolio cost versus risk exposure to help assess how each portfolio performs with respect to balancing cost and risk, as well as showing the cost-risk tradeoff for specific resource strategies.

Scenario Risk Analysis

In addition to modeling portfolio stochastic risks (the base stochastic simulation step in Figure 6.1), stochastic simulations were also conducted with various CO_2 emission cost adders to capture the risks associated with potential CO_2 emission compliance regulations. Since the probability of realizing a specific CO_2 emissions cost cannot be determined with a reasonable degree of accuracy, potential CO_2 emission costs were treated as a scenario risk in this IRP. PacifiCorp defines a scenario risk as an externally-driven fundamental and persistent change to the expected value of some parameter that is expected to significantly impact portfolio costs. This risk category is intended to embrace abrupt changes to risk factors that are not amenable to stochastic analysis.

The practice of combining stochastic simulation with CO_2 cost adder scenario analysis represents advancement with respect to the modeling approach used for PacifiCorp's 2004 IRP. Previously, the company simulated CO_2 scenario risks using several separate deterministic production cost runs.

Another scenario risk investigated in this IRP is potential widespread enactment of California's greenhouse gas emissions performance standard. (See Chapter 3, "California Greenhouse Gas Emissions Policies", for background information.) PacifiCorp used the CEM and PaR models to develop a portfolio that (1) excludes all new resources—generation and purchase contracts—that fail the emission performance threshold and (2) meets system-wide Renewable Portfolio Standard generation requirements stemming from assumed RPS enactment in all of PacifiCorp's west-side jurisdictions. Stochastic simulation of this portfolio yielded cost, risk, and CO_2 emission measures for comparison against other risk analysis portfolios. The results of this analysis are reported as the conclusion to Chapter 7.

PORTFOLIO PERFORMANCE MEASURES

Stochastic simulation results for the risk analysis portfolios were summarized and compared to determine which portfolios perform best according to a set of performance measures. These measures, grouped by category, include the following:

Cost

- Stochastic mean cost (Present Value of Revenue Requirements, or PVRR)
- Customer rate impact
- Environmental (emissions) externality cost
- Capital cost

Risk

- Risk exposure
- Production cost variability

Emissions

- Carbon dioxide emissions

Reliability

- Average annual Energy Not Served (ENS)
- Loss of Load Probability (LOLP)

The following sections describe in detail each of the performance measures listed above.

Stochastic Mean Cost

The stochastic mean cost for each risk analysis portfolio is the average of the portfolio's net variable operating costs for 100 iterations of the PaR model in stochastic mode, combined with the capital cost additions of new resources determined by the CEM for that portfolio.

The net variable cost from the PaR simulations, expressed as a net present value, includes system costs for fuel, variable plant O&M, unit start-up, market contracts, spot market purchases and sales. The variable costs included are not only for new resources but existing system operations as well. The capital additions for new resources (both generation and transmission) are calculated on an escalated "real-levelized" basis to appropriately handle investment end effects. Other components included in the stochastic mean PVRR include the value of renewable energy credits (green tags), renewable production tax credits, emission allowance costs and credits, and the cost assigned to Energy Not Served.[47]. Emission allowance costs or credits are determined outside of the CEM and PaR models and added to the PVRR as one of the final calculation steps.

[47] The cost of Energy Not Served is set to $400/MWh, which is the FERC wholesale electricity price cap now in effect for the California Independent System Operator. Note that PacifiCorp added this cost to its stochastic PVRR calculations subsequent to the distribution of early risk analysis portfolio results to public stakeholders in October 2006.

The PVRR measure captures the total resource cost for each portfolio. Total resource cost includes all the costs to the utility and customer for the variable portion of total system operations and the capital requirements for new supply and Class 1 demand-side resources as evaluated in this IRP. In addition, the PVRR accounts for emissions adders used for costing environmental externalities.

Customer Rate Impact

In addition to PVRR measures, PacifiCorp calculates the per-megawatt-hour customer rate impact associated with each of the risk analysis portfolios.

The rate impact measure is the change in the customer dollar-per-megawatt-hour price for the period 2012 through 2026, expressed on a levelized net present value basis. This approach differs from the one used for the 2004 IRP in two respects. First, the rates represent stochastic mean values from the Monte Carlo simulations rather than deterministic values. Second, the rate is a single summary change measure. In contrast, the 2004 IRP reported just the year-to-year impacts.

The dollars in the rate numerator consist of the stochastic mean system operating cost (fuel cost, cap-and–trade environmental cost, and variable O&M costs of all resources), combined with the fixed O&M and capital costs of the new supply-side and transmission resources.[48] The rate denominator is the retail load. The present value calculations use a 7.1% discount rate.

It should be noted that this measure provides an indication of the comparative rate impacts across risk analysis portfolios, but is not intended to accurately capture projected total system revenue requirements. For example, planned upgrades for current stations such as pollution controls added under PacifiCorp's Clean Air Initiative, as well as hydro relicensing costs, are not included in the calculations. Likewise, the IRP impacts assume immediate ratemaking treatment and make no distinction between current or proposed multi-jurisdictional allocation methodologies.

Environmental Externality Cost

For this IRP, PacifiCorp quantified environmental externalities by using externality cost adders for air emissions impacts—an approach that is consistent with prior company IRPs. 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. The DSM potentials study to be completed in June 2007 addresses environmental externalities not currently included in this IRP.

[48] New IRP resource capital costs are represented in 2006 dollars and grow with inflation, and start in the year the resource added. This method is used so resources having different lives can be evaluated on a comparable basis. The customer rate impacts will be lower in the early years and higher in the later years when compared to customer rate impacts computed under a rate-making formula.

The externality cost adder is treated as a variable cost in both the CEM and PaR models, and therefore is accounted for in each model's dispatch solution. Cost adders are included for CO_2, SO_2, NO_X, and mercury (Hg) emissions. See Chapter A of the Technical Appendix for information on pollutant allowance prices used in the IRP models.

Modeling the Impact of CO_2 Externality Costs on Forward Electricity Prices

PacifiCorp currently uses an inflation-adjusted CO_2 allowance price of $8/ton (2008$) in its calculation of official forward electricity price curves. These official price curves serve as the wholesale electricity price inputs to both the CEM and PaR models. For alternative CO_2 cost adders, new price curves are estimated using the Company's market price forecasting model, MIDAS.

The forward price curves need to account for the effect of a CO_2 allowance market on forecasted natural gas, SO_2 allowance, and NO_X allowance prices. PacifiCorp contracted with ICF Consulting to estimate these interaction effects for use in developing the forward electricity prices needed for the CO_2 cost adder scenarios.

ICF used their national power market simulation tool, IPM®, to develop natural gas, SO_2 allowance, and NO_X allowance prices taking into account the CO_2 allowance prices provided by PacifiCorp. The IPM® simulations used ICF's "expected case" model run as the starting point for forecast development.

Allowance trading markets for NO_X and SO_2 currently exist, while a market for mercury is slated to start in 2010. Carbon emissions are currently not regulated except in California. To simulate the impacts of allowance trading, allowance costs and credits are estimated outside of the CEM and PaR models using a spreadsheet model. The allowance trading calculations use baseline annual emissions caps along with the PaR model's annual emission quantities for a portfolio simulation. (For a stochastic simulation, the calculations use the average emissions across the 100 iterations.) Annual emissions above a cap are multiplied by the per-ton annual allowance price (or in the case of mercury, a per-pound price), while emissions below the cap are assigned a cost credit equal to the difference between the cap and the actual emissions multiplied by the allowance price. Note that as a simplifying assumption, all allowances are traded in the year accrued. The resulting net present value of the 20-year stream of annual allowance balances is included in the PVRR.[49]

PacifiCorp modeled future carbon regulation scenarios assuming that CO_2 emissions are capped to 2000 levels, and that a CO_2 allowance trading market begins in 2010. In recognition of the timing uncertainty, 2010 CO_2 costs are probability-weighted by a factor of 0.50. Likewise, 2011 costs are weighted by a factor of 0.75. By 2012, the full inflation-adjusted CO_2 allowance cost is imposed, growing at inflation thereafter.

The CO_2 adder scenario simulations were performed with five adder levels: $0, $8, $15, $38, and $61 per ton (in 2008 dollars). For the $61/ton cost adder, the cap-and-trade program is assumed to start in 2010, but is not fully phased in until 2016.

As a key performance measure, PacifiCorp reports the emissions externality cost as the increase in stochastic mean PVRR relative to the $0 adder case at each successively higher CO_2 adder level. For the set of risk analysis portfolio finalists, the externality cost is calculated as a tax

[49] To avoid double counting, the emission adder cost is backed out of the PaR model's total production cost.

(emission quantity multiplied by the emissions cost adders) as well as a net allowance cost balance under a cap-and-trade regime for all pollutants.

Risk Exposure

Risk exposure is the stochastic upper-tail mean PVRR minus the stochastic mean PVRR. The upper-tail mean PVRR is a measure of high-end stochastic risk, and is calculated as the average of the five stochastic simulation iterations with the highest net variable cost. Risk exposure is somewhat analogous to Value at Risk (VaR) measures. The fifth and ninety-fifth percentile PVRRs are also reported. These PVRR values correspond to the iteration out of the 100 that represents the fifth and ninety-fifth percentiles, respectively. These measures represent snapshot indicators of low-risk and high-risk stochastic outcomes.

Capital Cost

The total capital cost measure is the sum of the capital costs for generation resources and transmission, expressed as a net present value.

Production Cost Variability

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost for the 100 Monte Carlo simulation iterations. The production cost is expressed as a net present value for the annual costs for 2007 through 2026.

Carbon Dioxide Emissions

Carbon dioxide emissions are reported for two time periods: 2007–2016 and 2007–2026. The 10-year view excludes the emissions impact of growth stations—generic combined cycle units that serve primarily to meet load growth beyond the 10-year investment window.

For risk analysis portfolios considered as finalists for preferred portfolio selection, CO_2 emissions are reported for both generation sources (direct emissions) as well as combined with the net effect of wholesale market activity. The emission contribution assigned to market purchases (indirect emissions, net of emission credits from wholesale sales). The indirect CO_2 emissions related to purchases are calculated by multiplying net purchased power generation by an average emissions factor of 0.565 tons/MWh which is offset by emissions deemed to go with wholesale sales at the average system emission rate. This factor is based on actual 2005 purchases, and is applied through the 20-year forecast. The total system emissions footprint (generation only) for sulfur dioxide, nitrogen oxides, mercury is also reported for the period 2007–2026.

Supply Reliability

Energy Not Served

Energy Not Served is a condition where there is insufficient generation available to meet load because of physical constraints or market conditions. Certain iterations of a PaR stochastic simulation will have "Energy Not Served" or ENS. This occurs when an iteration has one or more stochastic variables with large random shocks that prevent the model from fully balancing the system for the simulated hour. Typically large load shocks and simultaneous unplanned plant outages are implicated in ENS events. For example, a large load shock in a transmission-constrained topology bubble would yield a relatively large amount of ENS. Running the PaR model in stochastic mode without including the stochastic variability of load yields virtually no ENS over the planning horizon. Similarly, deterministic PaR simulations do not experience ENS because there is no random behavior of model parameters; loads increase in a smooth fashion over time.

The stochastic ENS results, averaged across all 100 iterations, are used to compare the reliability among portfolios when stressed. Consequently, stochastic ENS results are indicative of relative differences in portfolio reliability given extreme modeled conditions with low probability of occurrence, and are not intended to represent indicators of expected system reliability under normal conditions. It is noteworthy that in actual practice PacifiCorp has not needed to shed retail load, other than the curtailment contract customers, due to a resource shortage.

For reporting of the ENS statistics, PacifiCorp calculates an average annual value for 2007 through 2016 in gigawatt-hours, as well as the upper-tail ENS (average of the five iterations with the highest ENS). Simulations using the \$8/ton CO_2 cost adder are reported, as the adder level does not have a material influence on ENS results.

Loss of Load Probability

The new IRP guidelines issued in January 2007 by OPUC (Order 07-002) state:

> "*Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios.*"

To meet the LOLP guideline, PacifiCorp developed a metric and applied it to the risk analysis portfolios simulated with the Planning and Risk model.

Loss of Load Probability is a term used to describe the probability that the combinations of online and available energy resources cannot supply sufficient generation to serve the load peak during a given interval of time.

Mathematically, LOLP is a simple concept:

$$\mathbf{LOLP} = \Pr(\mathbf{S} \leq \mathbf{L})$$

*where **S** is a random variable representing the available power supply, and **L** is the daily load peak where the peak load is regarded as known.*

Traditionally LOLP was calculated for each hour of the year, converted to a measure of statistically expected outage times or number of outage events (depending on the model), and summed for the year. The annual measure estimates the generating system's reliability. A high LOLP generally indicates a resource shortage, which can be due to generator outages, insufficient installed capacity, or both. Target values for annual system LOLP depend on the utilities' degree of risk aversion, but a level equivalent of one day per ten years is typical. Loss of load probability is considered a limited measure of reliability, and does not account for numerous risk factors, utility agreements, and other considerations that govern the operation of the utility network.

For reporting LOLP, PacifiCorp calculates the probability of Energy Not Served events, where the magnitude of the ENS exceeds given threshold levels. PacifiCorp is strongly interconnected with the regional network; therefore, only events that occur at the time of the regional peak are the ones likely to have significant consequences; of those events, small shortfalls are likely to be resolved with a quick (though expensive) purchase. In Chapter 7, the proportion of iterations with ENS events in July exceeding selected threshold levels are reported for each risk analysis portfolio simulated with the PaR module. The LOLP is reported as a study average as well as year-by-year results for an example threshold level of 25,000 Megawatt-hours. This threshold methodology follows the lead of the Pacific Northwest Resource Adequacy Forum, which reports the probability of a "significant event" occurring during the winter season.

PREFERRED PORTFOLIO SELECTION

The preferred portfolio is selected from among the risk analysis portfolios primarily on the basis of relative cost-effectiveness, customer rate impact, and the balance between cost and risk exposure. Also important is the robustness of the portfolios with respect to their cost and risk performance under successively higher CO_2 adder scenarios; the portfolios that consistently rank the highest regardless of the assumed CO_2 adder are strong contenders for selection as the preferred portfolio. Supply reliability risk and CO_2 emissions are also important, but play a lesser role in selecting the preferred portfolio because differences among portfolios with respect to these measures are relatively small.

These primary selection criteria are in line with state IRP guidelines that dictate that the preferred portfolio be least-cost after accounting for uncertainty, risk, and the long-run public interest.

CLASS 2 DEMAND-SIDE MANAGEMENT PROGRAM ANALYSIS

Decrement Analysis

For the Class 2 demand-side management decrement analysis, the preferred portfolio was used to calculate the reduced system operating costs (or decrement value) of various types of Class 2 programs. PacifiCorp will use these decrements values when evaluating the cost-effectiveness of current programs and potential new DSM programs between IRP cycles.

The process used for this IRP is to model Class 2 DSM program types as contracts that supply energy according to hourly load shapes provided by PacifiCorp's DSM department. These contracts serve as surrogates for direct load reductions attributable to energy efficiency programs. The Planning and Risk Module is then run in stochastics mode with and without the Class 2 DSM resources to establish the change in system cost (reduction in the stochastic mean PVRR for 100 simulations) from lower market purchases or resource re-optimization due to the addition of the Class 2 DSM. This approach differs from that used in the 2004 IRP. For the 2004 IRP, the load decrements were modeled as reductions in the load forecasts, with system cost differences determined by deterministic PaR runs. The new approach simplifies the data set-up process and accounts for stochastic risk in the cost estimates.

To determine the Class 2 DSM decrements, 12 shaped planning decrements, each at 100 megawatts at peak, were modeled starting in 2010 throughout the 20-year IRP study period. The decrements are shaped to each of the following loads for both the east and west control areas. Table 6.5 below provides an overview of the planning decrement design, showing the load size (load factor) and end-use hourly load shape.

Table 6.5 – Planning Decrement Design

Decrement Size	East System Load Center	West System Load Center	End-Use Hourly Load Shape
100 MW	7% Load Factor	20% Load Factor	Residential Cooling
100 MW	60% Load Factor	60% Load Factor	Residential Lighting
100 MW	46% Load Factor	n/a	Residential Whole House
100 MW	16% Load Factor	16% Load Factor	Commercial Cooling
100 MW	49% Load Factor	49% Load Factor	Commercial Lighting
100 MW	n/a	28% Load Factor	Residential Heating
100 MW	East load shape (approx. 65% Load Factor)	West load shape (approx. 67% Load Factor)	East/West System Load

The company will evaluate additional DSM program opportunities by replacing the forward-market-price avoided cost used in the traditional DSM cost effectiveness tests with the shaped decrement values. For such evaluations, the decrement values will be pro-rated to match the load shape of new DSM proposals. Once new programs are implemented, their contributions to load reductions will be incorporated directly into the load forecast used for the next IRP.

Public Utility Commission Guidelines for Conservation Program Analysis in the IRP

During the 2007 integrated resource planning process and development of the company's Class 2 energy efficiency resource assessment, there were questions raised as to whether PacifiCorp had sufficient information available, absent the completion of a system-wide demand-side resource assessment study, to arrive at a fair representation of the energy efficiency resource potential available over the planning period. While having additional data from such a study would likely have provided additional clarity around this assessment, the company had several other reliable sources of information from which to arrive at a forecast of achievable resource potential as represented within the 2007 IRP. These sources have been used for prior planning exercises and continue to be used to identify significant resource opportunities. Additionally, these sources have proven reliable in the past in helping the company achieve verifiable results.

Class 2 energy efficiency resources comprise a significant portion of the overall demand-side management investments and resource targets within the 2007 IRP. There are approximately 250 MWa of Class 2 energy efficiency resources accounted for within the 2007 preferred portfolio. These resources were identified through a composite of resource assessment exercises conducted over the last five years. These assessments, coupled with the performance of the company's existing demand-side resource portfolio and associated lessons-learned, aided PacifiCorp in the development of the 2007 Class 2 energy efficiency plan contributions. The studies and information sources relied upon included market-specific as well as measure-specific characterization studies/work, third-party program process and impact evaluations, regional assessments such as the Northwest Power Planning Council's 5th Power Plan, the Energy Trust of Oregon's forecast, demand-side management advisory groups, and others. These sources represent the most relevant information available from which to draw assumptions regarding resource potential. The company's confidence in this information is reflected in their use for adjusting the 2007 plan's load forecast, indicating they will be acquired within cost-effective parameters.

To avoid foreclosing opportunities to exceed the 250 MWa target already established for the IRP until a new target can be defined using the results of the multi-state DSM potentials study, the company intends to use the Class 2 DSM decrement analysis described above to establish values, at various load shapes, of 200 MWa of incremental resource acquisitions (beyond the 250 MWa in the 2007 IRP) that might present themselves between planning cycles. However, since the amounts and shapes, availability, timing and acquisition costs are less certain than the resources from existing programs and assessments, they were not placed within the company's 2007 load and resource balance. As these resources are identified and determined to be cost-effective based on the decrement values, they will be incorporated into the next integrated resource plan update.

Modeling of demand-side resources in the 2007 integrated resource planning process is robust and treats them as functionally equivalent to supply-side resources, even without the utilization of specific supply curves. Forecasted loads are reduced by the known and certain demand-side management resources in much the same manner that a supply-side resource would offset the load.

In regards to additional assessment work, PacifiCorp will complete a comprehensive system-wide demand-side resource market assessment by late June, 2007. At that time, the company will begin incorporating the results of that assessment, in addition to the sources identified above and used during this IRP planning cycle, into the planning assumptions and forecasts going forward. Once the system-wide demand-side resource assessment information is available, both the incremental 200 MWa amount as well as the Class 2 DSM modeling methodology will be revisited to assure that the planning process places the appropriate dependence on demand-side resources commensurate with their availability.

In summary, while the potential study and supply curves will refine the company's approach to assessing and modeling demand-side management resources, the current practices and approaches do not arbitrarily limit the amount, the value or potential acquisition of cost-effective energy efficiency resources within the current plan.

7. MODELING AND PORTFOLIO SELECTION RESULTS

Chapter Highlights

- PacifiCorp assessed 16 alternative future scenarios to determine resources and capacity quantities suitable for inclusion in risk analysis portfolios. Based on the Capacity Expansion Module's optimized investment plans, the company selected wind (a proxy for all renewables), combined heat and power, supercritical pulverized coal (SCPC), combined cycle combustion turbine (CCCT), single-cycle combustion turbine (SCCT), integrated gasification combined cycle (IGCC), load control programs, and short-term market purchases (front office transactions) in subsequent portfolio studies.

- The company initially studied 12 portfolios using its stochastic production cost simulation model. These portfolios tested a variety of resource strategies, distinguished by the planning reserve margin and the quantity of wind, pulverized coal, front office transactions, and IGCC resources included.

- The stochastic modeling results for the 12 portfolios indicate that the best strategy for achieving a low-cost, risk-informed portfolio is to include supercritical pulverized coal along with additional wind and natural gas resources to mitigate CO_2 cost risk.

- PacifiCorp evaluated a second set of five portfolios to account for (1) new and evolving state resource policies that place constraints on the company's resource choices, and (2) new Wyoming load growth information. All of these portfolios included 600 megawatts of additional wind (incremental to the original 1,400-megawatt renewables commitment), 100 megawatts of CHP, and 95 megawatts of new load control programs.

- The analysis of the original 12 portfolios informed the development of the second set of portfolios; these portfolios focused on the timing of SCPC plants, the mix of gas-fired plants and market purchases to address east-side load growth, the timing and type of resources needed to make up for the loss of the BPA peaking contract in 2011, and the planning reserve margin level.

- Based on superior performance with respect to stochastic cost, customer rate impact, cost vs. risk balance, and supply reliability, a portfolio with the following characteristics was chosen as the preferred portfolio:
  - A total of 2,000 megawatts of renewables by 2013
  - A west-side CCCT in 2011
  - High-capacity-factor baseload resources in the east in 2012 and 2014
  - East-side CCCTs in 2012 and 2016
  - Balance of system need fulfilled by front office transactions beginning in 2010

INTRODUCTION

This chapter presents modeling results for the portfolio analysis, as well as chronicles the development of the portfolios, the associated decision process that guided their formulation, and the selection of a preferred portfolio.

Discussion of the portfolio analysis results falls into the following six sections.

- **Alternative Future and Sensitivity Scenario Results** – This section presents the Capacity Expansion Module's optimized resource investment plans and PVRRs for the alternative future and sensitivity scenarios. These results constitute the outcome of the resource screening phase of the IRP modeling effort.
- **Risk Analysis Portfolio Development and Stochastic Simulation Results** – This section describes the derivation and resource specifications for the risk analysis portfolios, and then provides a comparative assessment based on the performance measures described in Chapter 6. Creation of fixed investment schedules for wind, demand-side management programs, and combined heat and power resources, is covered first, followed by a description of the portfolio design goals and alternative resource strategies used to formulate them. The section also presents findings on a cost-versus-risk exposure tradeoff analysis of the resource strategies. (As discussed in Chapter 6, risk exposure is defined as the upper-tail mean PVRR minus the overall stochastic mean PVRR.)
- **Selection of the Preferred Portfolio** – This section provides a consolidated view of the portfolio evaluation results to indicate which portfolio is the most desirable after cost, risk, reliability, CO_2 emissions, and state resource policy evolution are considered.
- **Fuel Diversity Planning** – This section describes how fuel source diversity is addressed in the 2007 Integrated Resource Plan.
- **Forecasted Fossil Fuel Generator Heat Rate Trend** – This section reports the system-average fossil fuel generator heat rate trend for the preferred portfolio. This information addresses a new Utah Commission IRP reporting requirement to support the PURPA Fuel Sources Standard.
- **Class 2 Demand-side Management Decrement Analysis** – This section presents the decrement values for Class 2 program evaluations using the preferred portfolio to calculate the system benefit.

ALTERNATIVE FUTURE AND SENSITIVITY SCENARIO RESULTS

Alternative Future Scenario Results

This section presents the modeling results and findings for the CEM alternative future studies. As a refresher, Table 7.1 repeats the alternative future specifications outlined in Chapter 6.

Table 7.1 – Alternative Future Scenarios

CAF #	Name	Coal Cost: CO_2 Adder/Coal Commodity Price	Gas/ Electric Price	Load Growth	Renewable Sales Percentage due to RPS	Renewable PTC Availability	DSM Potential
00	Business As Usual	None/Medium	Medium	Medium	Low	Yes	Medium
01	Low Cost Coal/High Cost Gas	None/Low	High	Medium	Medium	Yes	Medium
02	With Low Load Growth	None/Low	High	Low	Medium	Yes	Medium
03	With High Load Growth	None/Low	High	High	Medium	Yes	Medium
04	High Cost Coal/Low Cost Gas	High/High	Low	Medium	Medium	Yes	Medium
05	With Low Load Growth	High/High	Low	Low	Medium	Yes	Medium
06	With High Load Growth	High/High	Low	High	Medium	Yes	Medium
07	Favorable Wind Environment	High/Medium	High	Medium	High	Yes	Medium
08	Unfavorable Wind Environment	None/Medium	Low	Medium	Low	No	Medium
09	High DSM Potential	High/Medium	High	Medium	Medium	Yes	High
10	Low DSM Potential	None/Medium	Low	Medium	Medium	Yes	Low
11	Medium Load Growth	Medium/Medium	Medium	Medium	Medium	Yes	Medium
12	Low Load Growth	Medium/Medium	Medium	Low	Medium	Yes	Medium
13	High Load Growth	Medium/Medium	Medium	High	Medium	Yes	Medium
14	Low Cost Portfolio Bookend	None/Low	Low	Low	Medium	Yes	Medium
15	High Cost Portfolio Bookend	High/High	High	High	Medium	No	Medium

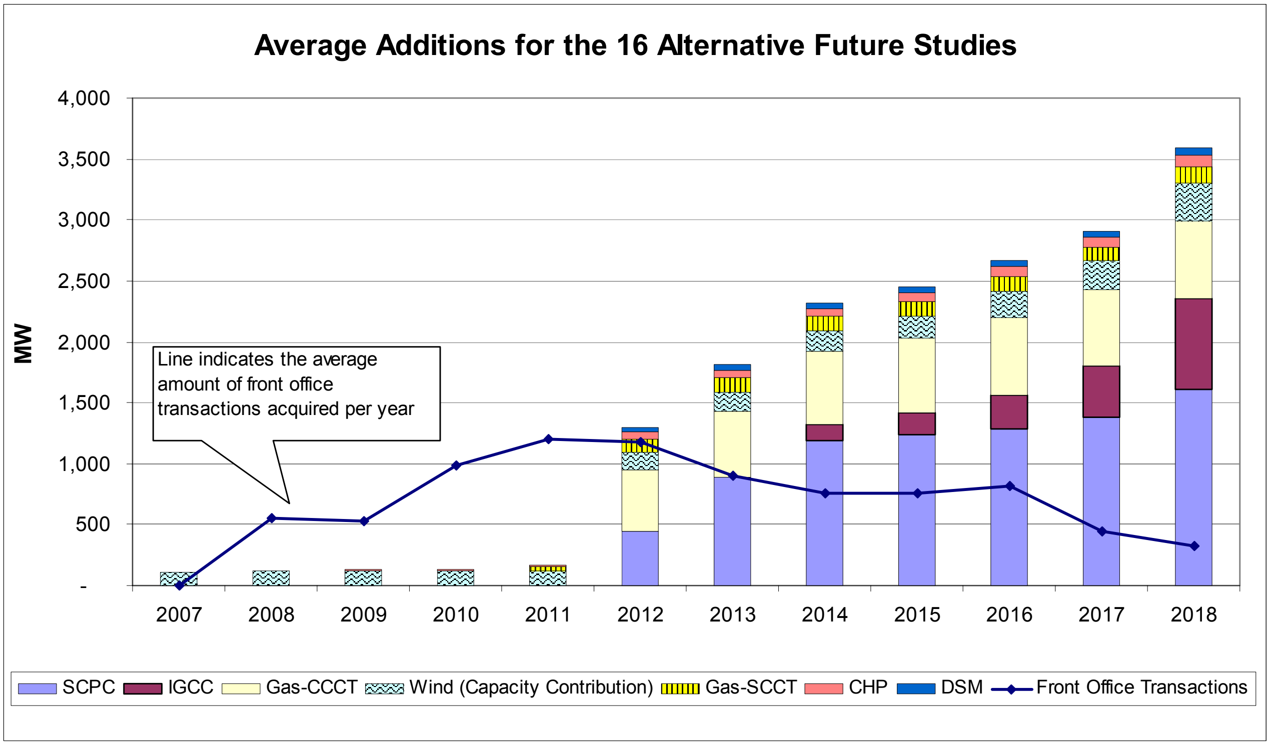
Table 7.2 reports the PVRR and total cumulative additions (2007–2018) by resource type for the 16 alternative future studies. The wind capacity contribution and average annual front office transactions acquired for 2007 through 2018 are also shown.

Table 7.2 – Alternative Future Scenario PVRR and Cumulative Additions for 2007-2018

Study	PVRR	Planning Reserve Margin	DSM - Class 1	DSM - Class 3	DSM-Total	Gas-CCCT-1x1	Gas-CCCT-2x1	Gas-CCCT	Gas-CHP	Gas-Frame	Gas-Total	Coal - IGCC	Coal - SCPC	Nameplate Wind	Wind Capacity Contribution	Total Nameplate	FOT - Avg 2007-2018	FOT - Avg 2007-2018 Plus PRM
CAF00	$ 19,619	15%	47	103	150				125		125	500	2,440	500	134	3,715	966	1,111
CAF01	$ 18,071	15%	48	103	151				25		25	2,002	2,440	1,100	217	5,718	669	769
CAF02	$ 11,022	15%	47	31	78							500	2,440	600	125	3,618	406	467
CAF03	$ 30,159	15%	87	82	169		602	602	125	634	1,361	2,510	2,440	3,100	514	9,580	748	860
CAF04	$ 30,504	15%	47	31	78		1,698	1,698	125		1,823			2,200	354	4,101	961	1,105
CAF05	$ 23,920	15%	47	52	99				125		125			2,100	317	2,324	796	916
CAF06	$ 40,002	15%	87	82	169	1,498	2,300	3,798	125		3,923			2,400	409	6,492	1,071	1,232
CAF07	$ 33,339	15%	32	26	58				100		100	500	2,440	3,600	568	6,698	753	866
CAF08	$ 18,858	15%	47	82	129		1,150	1,150	125		1,275		750			2,154	958	1,102
CAF09	$ 33,213	15%		64	64				100		100	500	2,440	3,100	514	6,204	733	843
CAF10	$ 19,002	15%	29	39	68		1,150	1,150	75		1,225		750	700	148	2,743	929	1,068
CAF11	$ 24,606	15%	105	106	211				125	634	759	500	2,440	1,800	342	5,710	876	1,007
CAF12	$ 17,689	15%	47	103	150				100		100	500	1,500	900	184	3,150	602	693
CAF13	$ 35,024	15%	127	106	233	392	602	994	125	634	1,753	2,002	2,440	2,700	467	9,128	1,000	1,150
CAF14	$ 13,689	15%	47	103	150				25		25		750	500	122	1,425	622	716
CAF15	$ 49,234	15%	95	103	198	784		784	125	302	1,211	2,510	2,440	3,100	514	9,459	913	1,049
CAF Averages	**$ 26,122**		**63**	**76**	**135**	**891**	**1,250**	**1,454**	**103**	**551**	**929**	**1,202**	**1,978**	**1,893**	**329**	**5,139**	**813**	**935**

Figure 7.1 provides a composite view of cumulative additions by resource type over time, averaged for all 16 alternative future investment plans. Annual front office transactions acquired are also shown.

Figure 7.1 – Cumulative Resource Additions by Year for Alternative Future Studies



Demand-side Management Program Selection Patterns

The CEM chose, on average, 135 megawatts of DSM resources across the alternative future studies—63 megawatts of Class 1 resources and 76 megawatts of Class 3 resources. The CEM selected Class 1 programs under all scenarios except one: the high DSM potential scenario. This result is covered under the DSM potential scenario discussion later in this section.

The highest individual amount selected for a scenario was 233 megawatts; this was for CAF13, the high load growth study. In contrast, the lowest amount was 58 megawatts under CAF07, the favorable wind environment scenario. It is apparent that conditions that support aggressive wind investment for the model have a dampening effect on the amount of DSM selected.

Table 7.3 shows the CEM's DSM additions for scenarios that included (1) low and high load growth assumptions, (2) low and high coal costs (based principally on the CO_2 adder level), and (3) low and high gas/electricity prices. The megawatt additions are reported as averages for the group of portfolios.[50]

[50] A complicating factor for interpreting the model's resource selection behavior is the impact of resource size. The model may find it advantageous to select a small resource to minimally meet the planning reserve margin constraint for a particular year, rather than invest in a larger yet less costly resource.

Table 7.3 – DSM Resource Selection by Alternative Future Type

Alternative Future Type	Number of Scenarios	Megawatt Average		
		Class 1 DSM	Class 3 DSM	Total
Low Load Growth	4	47	72	119
High Load Growth	4	89	84	178
Low Coal Cost	6	81	84	165
High Coal Cost	6	51	60	111
Low Gas/Electricity Prices	6	51	65	116
High Gas/Electricity Prices	6	52	68	120

DSM Potential Scenarios

The two DSM potential scenarios, CAF09 and CAF10, are intended to determine how other resource costs affect the CEM's choice of DSM resources at higher and lower levels of program participation. The High DSM potential scenario tests whether high fuel and market prices compensate for the higher DSM resource cost that accompanies greater program participation. The "low DSM potential" scenario tests the opposite set of conditions. Note that as the market potential increases, the resource cost ($/kW/yr) for most of the DSM programs is higher as well.[51] The higher cost reflects a greater level of incentive and administrative expenditures needed to maintain program savings at an elevated level.

As mentioned above, the CEM did not choose any Class 1 DSM programs under the high potential scenario, even with a high CO_2 adder and high gas and electricity prices in place. (On the other hand, the CEM selected 3,100 megawatts of wind.) The only DSM resources selected were the east and west demand buyback programs.

For the low potential scenario, CAF10, both Class 1 and Class 2 programs are selected. However, the combined amounts are only 4 megawatts greater than the DSM total under the high potential scenario.

Load Growth Scenarios

The alternative future scenarios CAF10, CAF11, and CAF12 test the CEM's resource preferences under a wide load growth range, holding other scenario variables constant. Table 7.4 profiles the resource additions for each of these load growth scenarios.

Table 7.4 – Resource Additions for Load Growth Scenarios

Load Growth Assumption	Scenario	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
		Cumulative Build Amounts (MW): 2007-2018				
Low	CAF12	150	1,500	500	100	900
Medium	CAF11	211	2,440	500	759	1,800
High	CAF13	233	2,440	2,002	1,753	2,700

[51] Critical Peak Pricing is the only program type for which unit resource costs decrease as the market potential increases.

The most interesting model behavior relates to the type of gas resource selected under each load growth scenario. For the low load growth scenario (CAF12), the model selects no central-station gas resources; instead, it relies mostly on coal builds. Under the medium load growth scenario (CAF11), the model then turns to SCCT frames and additional pulverized coal to address the higher loads, but no CCCT capacity was added to the investment plan at this point. (Wind nameplate capacity also doubled from 900 to 1,800 megawatts.) Under the high load growth scenario (CAF13), the next incremental resources selected were IGCC and CCCT, with the model having already selected all SCPC resources available to it under medium load growth conditions.

Tables 7.5, 7.6 and 7.7 show the CEM's resource additions for all scenarios that include the low, medium, and high load growth assumptions, respectively. The model tends to add pulverized coal first to meet incremental load growth, and then add significantly more gas and wind resources under the higher load growth scenarios. For all scenarios that include high load growth, the model chooses every SCPC resource available to it.

Table 7.5 – Resource Additions for Scenarios with Low Load Growth

	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
Scenario	**Cumulative Build Amounts (MW): 2007-2018**				
CAF02	78	2,440	500	-	600
CAF05	99	-	-	125	2,100
CAF12	150	1,500	500	100	900
CAF14	150	750	-	25	500
Average	**119**	**1,173**	**500**	**63**	**600**

Table 7.6 – Resource Additions for Scenarios with Medium Load Growth

	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
Scenario	**Cumulative Build Amounts (MW): 2007-2018**				
CAF00	150	2,440	500	125	500
CAF01	151	2,440	2,002	25	1,100
CAF04	78	-	-	1,823	2,200
CAF07	58	2,440	500	100	3,600
CAF08	129	750	-	1,275	-
CAF09	64	2,440	500	100	3,100
CAF10	68	750	-	1,225	700
CAF11	211	2,440	500	759	1,800
Average	**114**	**1,957**	**800**	**679**	**1,625**

Table 7.7 – Resource Additions for Scenarios with High Load Growth

	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
Scenario	**Cumulative Build Amounts (MW): 2007-2018**				
CAF03	169	2,440	2,510	1,361	3,100
CAF06	169	-		3,923	2,400
CAF13	233	2,440	2,002	1,753	2,700

	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
Scenario	**Cumulative Build Amounts (MW): 2007-2018**				
CAF15	198	2,440	2,510	1,211	3,100
Average	**136**	**2,440**	**1,207**	**1,030**	**1,925**

Gas/Electricity Price Scenarios

Tables 7.8 and 7.9 show the CEM resource additions for the six scenarios that include the low and high gas/electricity price assumptions, respectively.

With low prices, the model chose coal for only three of the six scenarios. Those three scenarios (CAF08, CAF10, CAF14), assumed no CO_2 adder, and only one coal plant was selected. The model selected wind for nearly all low-price scenarios, the exception being the "unfavorable wind environment" scenario, CAF08. Scenarios that also included the low coal cost assumption (CAF10, CAF14) had a relatively small amount of wind investment at 400 megawatts. For the scenario with a high coal cost and load growth (CAF06), the fossil fuel investment plant consisted of only CCCT resources at 3,798 megawatts.

Table 7.8 – Resource Additions for Scenarios with Low Gas/Electricity Prices

	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
Scenario	**Cumulative Build Amounts (MW): 2007-2018**				
CAF04	78	-	-	1,823	2,200
CAF05	99	-	-	125	2,100
CAF06	169	-	-	3,923	2,400
CAF08	129	750	-	1,275	-
CAF10	68	750	-	1,225	700
CAF14	150	750	-	25	500
Average	**116**	**375**	**-**	**1,399**	**1,317**

With high gas and electricity prices, the model invested heavily in both supercritical pulverized coal and wind, except for the scenario with low load growth. For all scenarios, every SCPC option was chosen (2,440 megawatts). Gas resources (CCCT and SCCT frame) were selected only for the two scenarios that also had high load growth (CAF03, CAF15). The model selected west IGCC resources in all scenarios, and added all the IGCC units available to it under the high price/high load growth scenario (CAF03).

Table 7.9 – Resource Additions for Scenarios with High Gas/Electricity Prices

	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
Scenario	**Cumulative Build Amounts (MW): 2007-2018**				
CAF01	151	2,440	2,002	25	1,100
CAF02	78	2,440	500	-	600
CAF03	169	2,440	2,510	1,361	3,100
CAF07	58	2,440	500	100	3,600
CAF09	64	2,440	500	100	3,100
CAF15	198	2,440	2,510	1,211	3,100

	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
Scenario	**Cumulative Build Amounts (MW): 2007-2018**				
Average	**120**	**2,440**	**1,420**	**466**	**2,433**

Carbon Dioxide Adder/Coal Cost Scenarios

Tables 7.10 and 7.11 show the CEM's resource additions for scenarios that have the low and high coal cost assumptions, respectively.

The CEM added 1,716 megawatts of supercritical pulverized coal capacity, on average, for the scenarios with low coal cost assumptions. As expected, the CEM built the most coal capacity when high gas/electricity prices and high load growth are included as assumptions (CAF1 and CAF3).

Table 7.10 – Resource Additions for Scenarios with Low CO_2 Adder/Coal Costs

	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
Scenario	**Cumulative Build Amounts (MW): 2007-2018**				
CAF00	150	2,440	500	125	500
CAF01	151	2,440	2,002	25	1,100
CAF02	78	2,440	500	-	600
CAF03	169	2,440	2,510	1,361	3,100
CAF08	129	750	-	1,275	0
CAF10	68	750	-	1,225	700
CAF14	150	750	-	25	500
Average	**124**	**1,716**	**787**	**577**	**929**

With high coal costs (Table 7.11), the model did not add any coal resources unless the scenario was accompanied by high gas/electricity prices. Base load gas was added in only three of the six portfolios. Substantial wind capacity was added in all scenarios, with an average of 2,750 megawatts (a 446-megawatt capacity contribution).

Table 7.11 – Resource Additions for Scenarios with High CO_2 Adder/Coal Costs

	DSM	Coal-SCPC	Coal-IGCC	Gas	Wind Nameplate
Scenario	**Cumulative Build Amounts (MW): 2007-2018**				
CAF04	78	-	-	1,823	2,200
CAF05	99	-	-	125	2,100
CAF06	169	-	-	3,923	2,400
CAF07	58	2,440	500	100	3,600
CAF09	64	2,440	500	100	3,100
CAF15	198	2,440	2,510	1,211	3,100
Average	**111**	**1,220**	**585**	**1,214**	**2,750**

Sensitivity Analysis Results

This section presents the modeling results for the CEM sensitivity analysis studies. As a refresher, Table 7.12 repeats the sensitivity scenario specifications outlined in Chapter 6.

Table 7.12 – Sensitivity Analysis Scenarios

SAS#	Name	Basis
01	Plan to 12% capacity reserve margin	Alternative Futures Scenario #11 ("Medium Load Growth")
02	Plan to 18% capacity reserve margin	Alternative Futures Scenario #11 ("Medium Load Growth")
03	CO_2 adder implementation in 2016	Alternative Futures Scenario #11 ("Medium Load Growth")
04	Regional transmission project	Alternative Futures Scenario #11 ("Medium Load Growth")
5-10 5-15 5-20	CO_2 adder impact on resource selection: test $15, $20, $25 per ton adders (approximately $10, $15, and $20 in 1990 dollars)	Alternative Futures Scenario #11 ("Medium Load Growth")
06	Low wind capital cost	Alternative Futures Scenario #11 ("Medium Load Growth")
07	High wind capital cost	Alternative Futures Scenario #11 ("Medium Load Growth")
08	Low coal price	Alternative Futures Scenario #11 ("Medium Load Growth")
09	High coal price	Alternative Futures Scenario #11 ("Medium Load Growth")
10	Low IGCC capital cost	Alternative Futures Scenario #11 ("Medium Load Growth")
11	High IGCC capital cost	Alternative Futures Scenario #11 ("Medium Load Growth")
12	Add a carbon-capture-ready IGCC to the portfolio (base case for SAS13 and SAS14)	Alternative Futures Scenario #11 ("Medium Load Growth")
13	Replace the IGCC resource in the SAS12 portfolio with a single-gasifier version	SAS #12
14	Replace the IGCC resource in the SAS12 portfolio with one that includes carbon sequestration	SAS #12
15	Plan to "average of super-peak" load	Alternative Futures Scenario #11 ("Medium Load Growth")
16	"Favorable Wind Environment" scenario assuming permanent expiration of the renewables PTC beginning in 2008	Alternative Futures Scenario #07 ("Favorable Wind Environment")

Table 7.13 reports the PVRR and total cumulative additions (2007–2018) by resource type for the 16 sensitivity studies. The wind capacity contribution and average annual front office transactions acquired for 2007 through 2018 are also shown. The study results are summarized below.

Table 7.13 – Sensitivity Analysis Scenario PVRR and Cumulative Additions, 2007-2018

Study	PVRR	Planning Reserve Margin	DSM - Class 1	DSM - Class 3	DSM-Total	Gas-CCCT-1x1	Gas-CCCT-2x1	Gas-CCCT	Gas-CHP	Gas-Frame	Gas-Total	Coal - IGCC	Coal - SCPC	Nameplate Wind	Wind Capacity Contribution	Total Nameplate		FOT - Avg 2007-2018	FOT - Avg 2007-2018 Plus PRM
SAS01	$ 24,400	12%	55	106	161				125		125	500	2,440	1,100	223	4,326		865	969
SAS02	$ 24,983	18%	55	106	161				100	634	734	500	2,440	1,700	326	5,535		936	1,104
SAS03	$ 22,673	15%	47	106	153				125	302	427	500	2,440	1,500	291	5,020		942	1,083
SAS04	$ 24,182	15%	113	106	219				125		125	997	2,440	2,400	409	6,181		896	1,031
SAS05-10	$ 28,551	15%	103	106	209		602	602	125	634	1,361	500	1,840	2,500	406	6,410		872	1,003
SAS05-15	$ 32,390	15%	127	106	233		602	602	125	634	1,361	500	1,090	3,100	514	6,284		935	1,075
SAS05-20	$ 36,073	15%	143	106	249		1,150	1,150	125	720	1,995		750	3,100	514	6,094		906	1,042
SAS06	$ 24,282	15%	55	106	161				125	634	759	500	2,440	2,600	422	6,460		806	927
SAS07	$ 24,836	15%	47	82	129				100	634	734	997	2,440	700	163	5,000		897	1,031
SAS08	$ 24,401	15%	95	103	198				125	302	427	500	2,440	1,300	253	4,865		920	1,058
SAS09	$ 24,980	15%	47	103	150				125	302	427	500	2,440	1,500	300	5,017		890	1,023
SAS10	$ 24,559	15%	47	103	150				125	332	457	997	2,440	1,100	223	5,144		889	1,023
SAS11	$ 24,660	15%	103	106	209				125	634	759	500	2,440	1,800	334	5,708		922	1,060
SAS12	$ 24,976	15%	103	106	209				100	332	432	1,250	2,440	1,000	196	5,331		915	1,052
SAS13	$ 24,980	15%	47	106	153				100	302	402	1,250	2,440	800	165	5,045		828	953
SAS14	$ 25,521	15%	95	106	201				100	332	432	1,250	2,440	1,000	196	5,323		848	975
SAS15	$ 24,412	15%	105	106	211				125	332	457	500	2,440	1,700	323	5,308		803	924
SAS16	$ 35,049	15%	47	26	73				75		75	500	2,440	3,500	580	6,588		649	727

Alternative planning reserve margins (SAS01 and SAS02)

Allowing the CEM to optimize to alternative planning reserve margins, 12% and 18%, had the following impacts:

- The PVRR was lowest for the 15% PRM base case portfolio (CAF11); the cost difference between the 15% PRM portfolio and 18% PRM was $6.9 billion, while the difference between the 12% PRM portfolio and the 15% PRM portfolio was $6.3 billion.
- There was no difference in the amount of supercritical pulverized coal or IGCC capacity among the portfolios
- None of the portfolios included CCCT capacity; SCCT capacity was added for 15% and 18% PRM portfolios (both at 634 megawatts)
- The 12% PRM portfolio had no base load gas resources, but included CHP
- Relative to the 12% PRM portfolio, the 15% PRM portfolio had more wind (700 megawatts) and more front office transactions
- Relative to the 15% PRM portfolio, the 18% PRM portfolio had more front office transactions and slightly less wind and DSM

CO_2 adder implementation in 2016, compared to 2012 for the base case portfolio

Moving back the start of CO_2 regulation from 2012 to 2016 had the following impacts on the base case portfolio:

- The PVRR decreased by $1.9 billion
- The resulting portfolio had less Class 1 DSM, less SCCT capacity, less wind, and more front office transactions

Inclusion of the regional transmission project[52]

- The project resulted in a $424 million decrease in PVRR relative to the base case portfolio

[52] The project consisted of new 1,500 MW capacity lines from Wyoming to the SP15 transmission zone in California, and from Utah to NP15.

- Changes to the resource mix included elimination of all SCCT capacity, the addition of an IGCC unit, more wind, and a small increase in front office transactions

Resource mix impact of increasing the CO_2 adder
Increasing the CO_2 adder in a step-wise fashion for the base case portfolios had the following impacts:

- From \$8 to \$15: The CEM removed the Utah SCPC resource (600 megawatts), and added a CCCT and 700 megawatts of additional wind; PVRR increased by \$3.9 billion
- From \$15 to \$20: The CEM removed a Wyoming SCPC (750 megawatts), and added 600 megawatts of additional wind, 24 megawatts of Class 3 DSM, and additional front office transactions (63 average annual megawatts); PVRR increased by another \$3.8 billion
- From \$20 to \$25: The CEM removed the small Utah SCPC and the west IGCC (500 megawatts), and added another east CCCT as well as an intercooled aero SCCT; in addition, the model added 16 megawatts of Class 1 DSM, but decreased front office transactions by average annual 29 megawatts; PVRR increased by another \$3.7 billion

Low and high wind capital cost
Lowering the wind capital cost by 10% had the following effects relative to the base case portfolio:

- The CEM added 800 megawatts of wind
- The PVRR decreased by \$800 million
- Class 1 DSM is reduced by 50 megawatts
- Front office transactions are reduced by an average annual 70 megawatts

Increasing the wind capital cost by 11% had the following effects relative to the base case portfolio:

- The CEM removed 1,100 megawatts of wind capacity
- An east IGCC resource was added (497 megawatts)
- The PVRR increases by \$231 million
- Front office transactions increased by an average annual 21 megawatts
- Class 1 DSM is reduced by 50 megawatts, apparently displaced by the other resource additions

Low and high commodity coal prices
Lowering the coal price for new coal resources had the following effects relative to the base case portfolio:

- The PVRR decreases by \$204 million
- The CEM removed the west SCCT (332 megawatts) and 500 megawatts of wind (90 megawatts capacity contribution)
- Front office transaction were increased by an average annual 44 megawatts, while DSM decreases by 13 megawatts

Raising the coal price for new coal resources has the following effects relative to the base case portfolio:

- The Wyoming SCPC plants were moved up a year, and the large and small Utah SCPCs switched places: the large 600-megawatt unit moved from 2018 to 2012, while the small 340-megawatt unit moved from 2012 to 2018. (The coal price change adversely affected the economics of the small Utah SCPC unit to a greater degree than for the large Utah SCPC unit). The timing change of the coal plants resulted in removal of a west SCCT (332 megawatts) and 300 megawatts of wind (42-megawatt capacity contribution)
- The PVRR increased by $375 million
- Front office transaction increased by an average annual 44 megawatts, while DSM decreases by 61 megawatts

Low and high IGCC capital cost

Lowering the IGCC capital cost had the following effects relative to the base case portfolio:

- The CEM added an east IGCC (497 megawatts), and moved up the 200-megawatt west IGCC from 2017 to 2016
- The CEM removed 700 megawatts of wind (119-megawatt capacity contribution), and a SCCT (302 megawatts)
- The PVRR decreased by $46 million
- Front office transactions increased by an average annual 13 megawatts

Raising the IGCC capital cost had the following effects relative to the base case portfolio:

- The west IGCC is deferred from 2017 to 2018, which increases front office transactions by an average annual 46 megawatts and raises PVRR by $54 million

Impact of switching from an IGCC with a spare gasifier to one with a single gasifier

This change reduced PVRR by $4 million. Resource impacts included switching the location of a SCCT from the west location to the east location in 2012, reducing wind by 200 megawatts (32-megawatt capacity contribution), and reducing front office transactions by an average annual 87 megawatts.

Cost impact of building an IGCC with carbon sequestration

Replacing a carbon-capture-ready IGCC with one that has carbon sequestration increased PVRR by $541 million. The IGCC replacement resulted in minor resource selection impacts; namely, Class 1 DSM increased by 48 megawatts, and front office transactions increased by an average annual 19 megawatts.

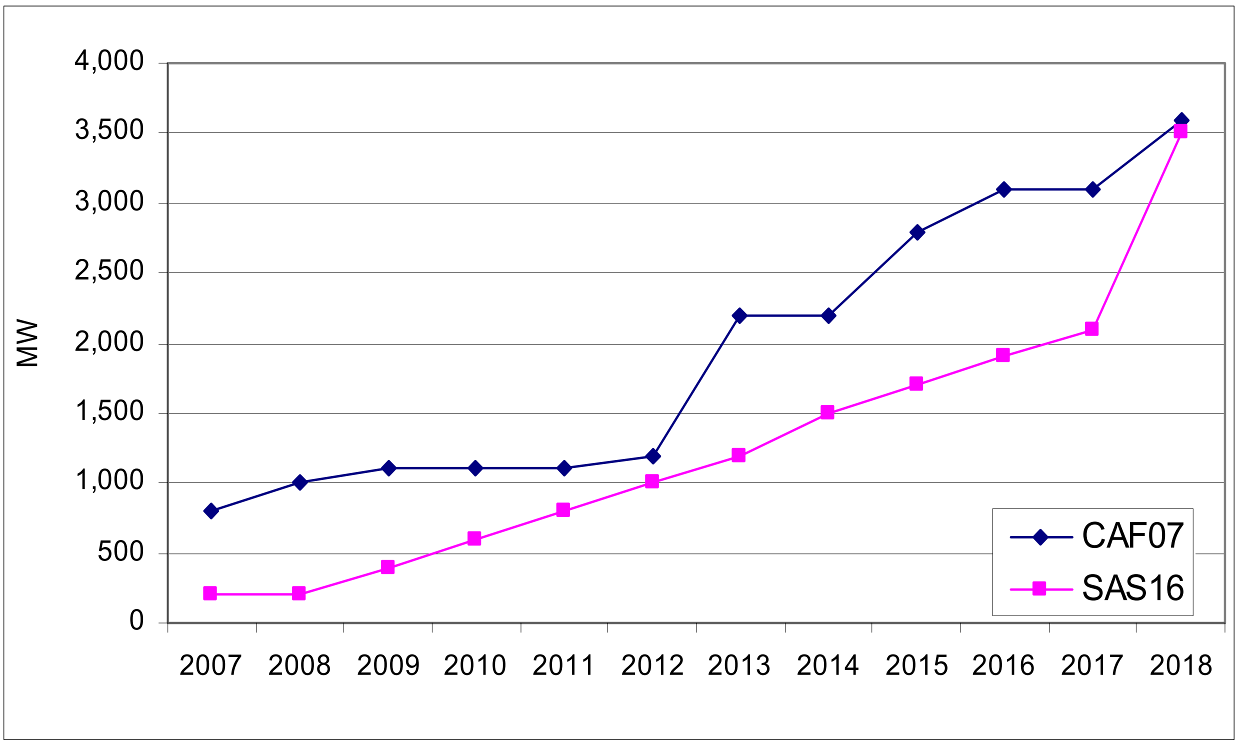
Plan to the average of the eight-hour super-peak period

Relative to the base case portfolio, CAF11, planning to the average of the eight-hour super-peak period decreases PVRR by $194 million. The resource impacts include: removal of a SCCT (302 megawatts), a decrease in wind capacity by 100 megawatts, and a reduction in front office transactions (103 megawatts on an average annual basis). DSM was unaffected.

Favorable wind development environment combined with expiration of the renewable production tax credit (PTC)

Comparing the portfolio PVRR for CAF07 and SAS16 indicates the impact of not renewing the PTC after 2008. The impact was found to be an additional $1.7 billion. Removing the PTC also significantly changed the wind investment schedule. Figure 7.2 compares the cumulative annual nameplate megawatt wind additions for CAF07 and SAS16. With no PTC in place (SAS16), the model chose to add wind in a smooth pattern until 2017, and then add 1,400 megawatts in 2018. This large capacity addition is an artifact of the timing of the generic growth stations, which start in 2019. With the PTC in place (CAF07), the wind addition schedule was lumpier, with significant additions in 2007, 2013, and 2015.

Figure 7.2 – Cumulative Wind Additions for CAF07 and SAS16



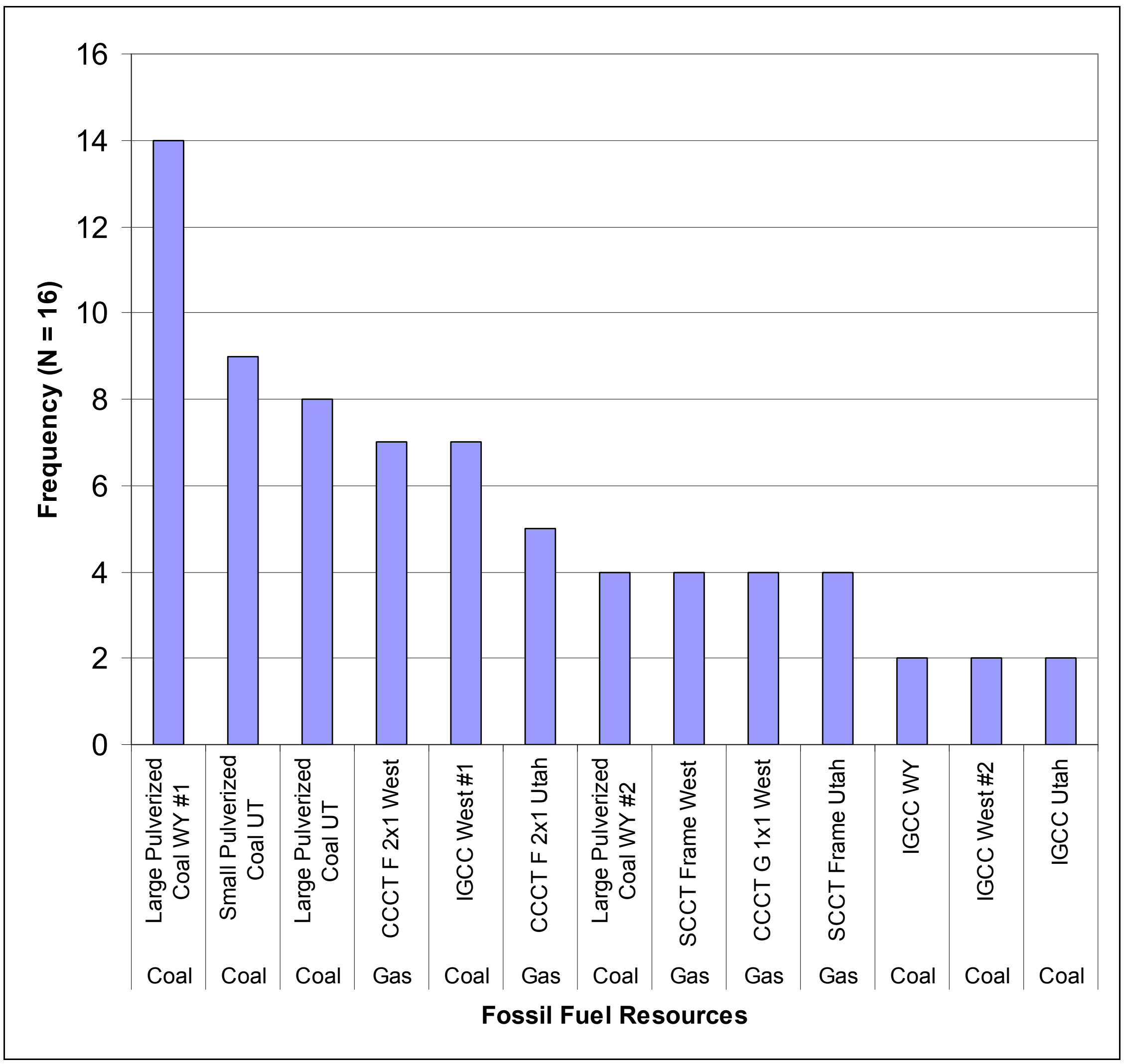
<u>Resource Selection Conclusions</u>

Based on the CEM modeling results, a number of general observations can be reached regarding the model's resource preferences, and what specific resources constitute robust selections to include in the risk analysis portfolios. First, supercritical pulverized coal was part of the resource stack in all the CEM portfolio solutions except for the three scenarios with high coal costs and low gas and electricity prices (CAF04, CAF05, and CAF06). Given that a high CO_2 adder is expected to put upward pressure on gas prices due to greater demand for cleaner power supplies, a scenario more in line with the "favorable wind environment" future (CAF07)—or the version of this scenario without renewable production tax credits (SAS16)—is a more realistic future. For these two scenarios, the model still selected supercritical pulverized coal and added it early in the study period.

A second observation concerns the model's selection frequency of the resources across the alternative future studies. Only two resources appeared in the majority of the studies: the large Wyoming and small Utah supercritical pulverized coal units. With few exceptions, the CEM added these coal units as soon as they were available for selection. Based on this result, PacifiCorp judged these coal resources to be robust options under the set of alternative futures evaluated. Figure 7.3 shows the selection frequency for all fossil fuel resources.

Regarding gas resource selection, CCCTs came into play only under scenarios that included low gas/electricity prices or high load growth. Selection of single-cycle combustion turbine frames appears to be sensitive to the level of load growth assumed; these resources were added for two scenarios with high load growth, as well as the medium load growth scenario. Given these selection patterns, gas plants are not judged to be robust resources under deterministic modeling conditions. However, it should be noted that the CEM deterministic runs do not capture the optionality value of gas resources; consequently, testing them in a stochastic modeling environment is necessary to estimate their full value in a diversified portfolio.

Figure 7.3 – CEM Fossil Fuel Resource Selection Frequency



Wind appeared in 15 out of the 16 alternative future studies. While this resource is considered robust as far as inclusion in the CEM's investment plans is concerned, unlike the pulverized coal resources, a robust *quantity* can't be determined due to the wide variance in selected wind capacities among the alternative future studies. Consequently, the company used measures of central tendency to determine an initial wind investment schedule for inclusion in the risk analysis portfolios. The development of the wind investment schedule is described in the next section.

The CEM chose IGCC for 10 out of the 16 alternative futures, with the west IGCC units (total of 500 megawatts) selected in seven futures and the east IGCC units selected in four futures. The model's selection of east-side IGCC resources was predicated on the high load growth assumption, and these resources were generally added beyond the 10-year investment horizon (2007–2016).

RISK ANALYSIS PORTFOLIO DEVELOPMENT – GROUP 1

To develop the first risk analysis portfolio, PacifiCorp first combined the fixed wind, DSM, and CHP investment schedules described below, along with the other resource options. The CEM was then executed with this set of resources *using the medium-case assumptions adopted for the alternative future studies*. The resulting CEM investment plan, labeled as RA1, thus parallels the plan that resulted from the "medium case" alternative future (CAF11) run. To derive subsequent risk analysis portfolios, PacifiCorp applied one or a combination of alternative resource strategies to RA1 or other variants of RA1 prior to CEM execution.

Twelve portfolios were initially developed with input received from public stakeholders during the fall of 2006. PacifiCorp used the associated portfolio simulation results and the analysis supporting the 10-year Business Plan to formulate a "base case" resource proposal that was shared with regulators.

The feedback received on the resource proposal, as well as recent external events[53] and an assessment of state resource policy directions, prompted the company to investigate portfolio alternatives that recognize existing and expected state resource acquisition constraints. A new set of risk analysis portfolios was consequently created to address these constraints while still adhering to system planning principles and the states' IRP development guidelines. (The new risk analysis portfolios also account for the revised load forecast.)

This second portfolio group constitutes the "finalists" from which the preferred was selected. The original set of 12 risk analysis portfolios informed the construction of these new portfolios. This chapter documents both sets of portfolios, which are referenced as "Group 1" and "Group 2".

[53] These events, cited in Chapter 3, include the Oregon PUC rejection of the 2012 RFP for baseload resources and issuance of new IRP guidelines (January 2006), adoption of renewable portfolio standards in Washington, California's adoption of a green house gas emissions performance standard, and introduction of climate change legislation in both Oregon and Washington.

Fixed Resource Additions for Risk Analysis Portfolios

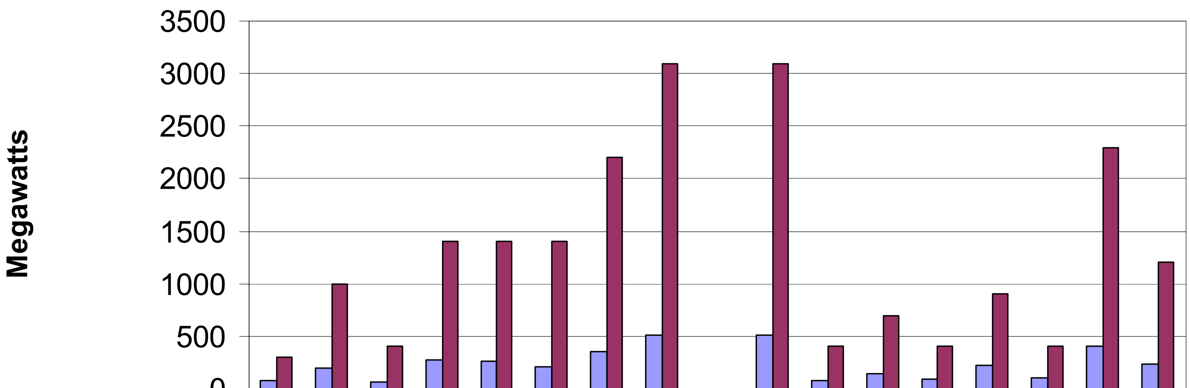
Renewables

A fixed wind resource investment schedule was included in all risk analysis portfolios. PacifiCorp developed an initial wind investment schedule based on a composite view of the resource addition patterns for the 16 alternative future scenarios covering the period 2007 through 2016. This initial wind investment schedule was modified as appropriate to support the testing of alternative resource strategies.

The CEM selected a wide range of wind resource capacities across the alternative future scenarios, from zero capacity for CAF08 ("unfavorable wind environment") to 3,100 megawatts of nameplate capacity for two scenarios (CAF07, "favorable wind environment" and CAF09, "high DSM potential"). The average nameplate amount for the 16 scenarios was 1,213 megawatts (for a capacity contribution of 235 megawatts), while the median amount was 950 megawatts. The amount selected for the medium case scenario was 700 megawatts. The most frequently occurring amount was 400 megawatts for four scenarios.

Figure 7.4 shows the amount of wind capacity that the CEM selected for each of the alternative future scenarios. Both nameplate capacity and capacity contribution are shown.

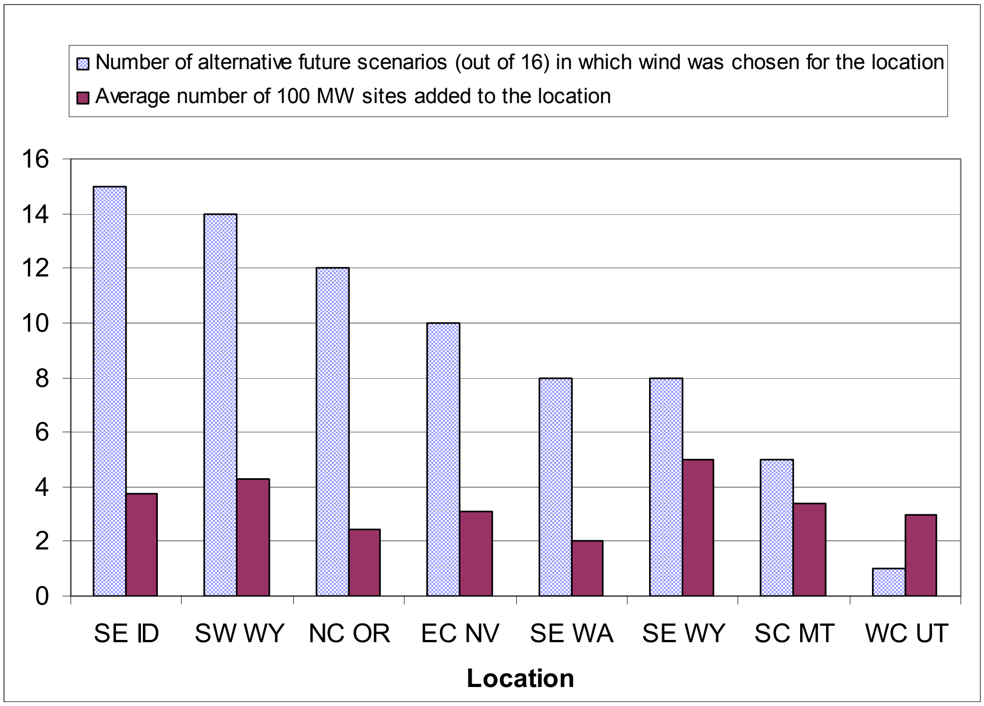
Figure 7.4 – Wind Capacity Preferences for Alternative Future Scenarios



	CAF00	CAF01	CAF02	CAF03	CAF04	CAF05	CAF06	CAF07	CAF08	CAF09	CAF10	CAF11	CAF12	CAF13	CAF14	CAF15	Ave.
Wind Capacity Contribution	82	196	60	277	259	215	354	514	0	514	85	148	95	222	99	410	235
Renew ables Nameplate	300	1,000	400	1,400	1,400	1,400	2,200	3,100	-	3,100	400	700	400	900	400	2,300	1213

Figure 7.5 profiles the CEM's location preferences for wind resources across the alternative future portfolios. It shows the number of scenarios in which wind was selected by location, and the average number of 100 megawatt project sites selected for each location four sites—Southeast Idaho, Southwest Wyoming, North Central Oregon, and East Central Nevada—appeared in the majority of the scenarios. The southeast Wyoming location (SE WY) had the largest number of sited added.

Figure 7.5 – Wind Location Preferences for Alternative Future Scenarios



Given these model results, a total nameplate capacity of 1,000 megawatts (capacity contribution of 217 megawatts) was added to each of the risk analysis portfolios and distributed among the sites favored by the model. Note that this capacity amount is in addition to the 400 megawatts considered a planned resource for 2007 and reflected in PacifiCorp's load and resource balance. Table 7.14 shows the resource addition schedule for 2008 through 2016 adopted for the risk analysis portfolios.

Table 7.14 – Wind Resource Additions Schedule for Risk Analysis Portfolios

Year	Annual Additions, Nameplate Capacity (MW)	Location	Cumulative Wind Nameplate Capacity (MW)	Cumulative Wind Peak Capacity Contribution (MW)
2008	200	North Central Oregon; Southeast Idaho	200	62
2009	200	North Central Oregon; Southeast Idaho	400	110
2010	100	Southeast Idaho	500	127
2011	-	-	500	127
2012	300	Southwest Wyoming	800	189
2013	200	Southwest Wyoming	1,000	217

Class 1 Demand-side Management Programs

A fixed megawatt amount of certain Class 1 demand-side management programs were included in all risk analysis portfolios based on a review of DSM addition patterns covering the 2017-2016 investment horizon for the alternative future scenarios. In order to be selected for risk analysis portfolio inclusion, programs needed to have been chosen in the medium case scenario (CAF11) or a majority of the other alternative future scenarios, as well as have a capacity that exceeds 10 megawatts when selected. This combination of criteria is meant to strike a balance between a relatively aggressive DSM implementation pattern for the risk analysis portfolios (accounting for the fact that not all potential system benefits can be readily quantified and captured in the CEM solution) and constraining the entire set of CEM options to a reasonable number.

For the medium case scenario, the CEM chose the following programs, megawatt quantities (as measured at the customer meter), and installation years:

- East-side summer direct load control – 48 megawatts in 2013
- West-side summer direct load control – 8 megawatts in 2013
- East-side commercial/industrial direct load control – 2 megawatts in 2013
- East-side scheduled irrigation – 15 megawatts in 2012
- West-side scheduled irrigation – 32 megawatts in 2012

The only resources that the CEM selected for the majority of alternative future scenarios were the east-side and west-side scheduled irrigation programs. The CEM selected the east-side program in 11 out of 16 scenarios, while the west-side program was selected in 10 out of 16 scenarios. Figures 7.6 and 7.7 show the number of scenarios in which program types were selected by the CEM and the average megawatts for all scenarios, respectively.

Regarding the CEM's selection of program installation dates, 2012 and 2013 were the most common across the alternative future scenarios. Only under the high-cost bookend scenario (CAF15) are programs selected for implementation earlier than 2010. For this scenario, several programs are added in 2008, such as east-side scheduled irrigation and the three east-side direct load control programs (summer, winter, and commercial/industrial).

Figure 7.6 – Class 1 DSM Selection Frequency for Alternative Future Scenarios, 2007-2016

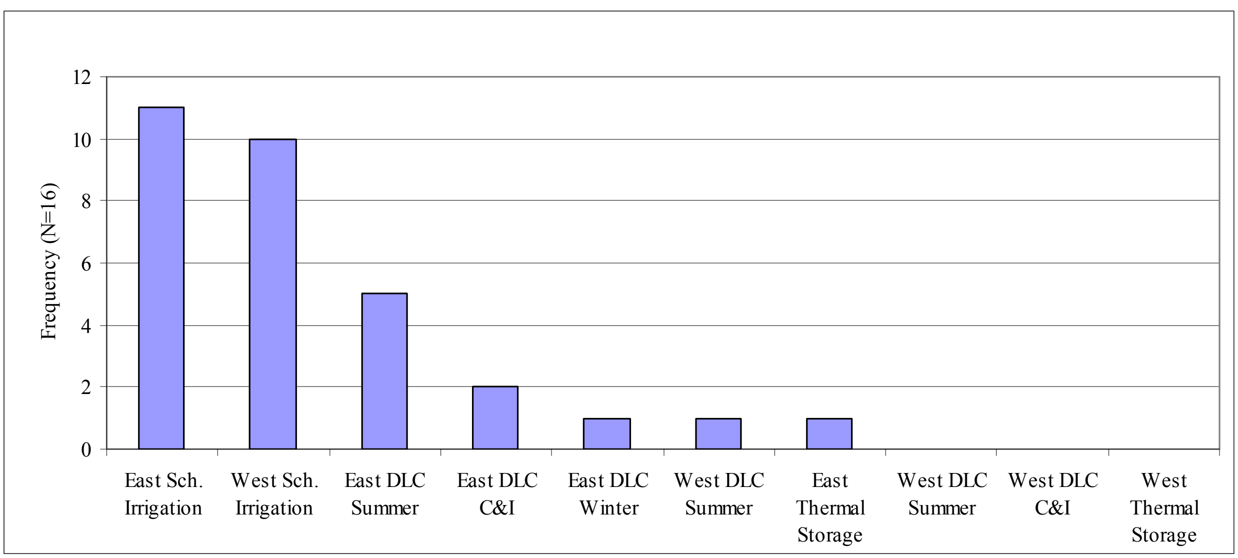
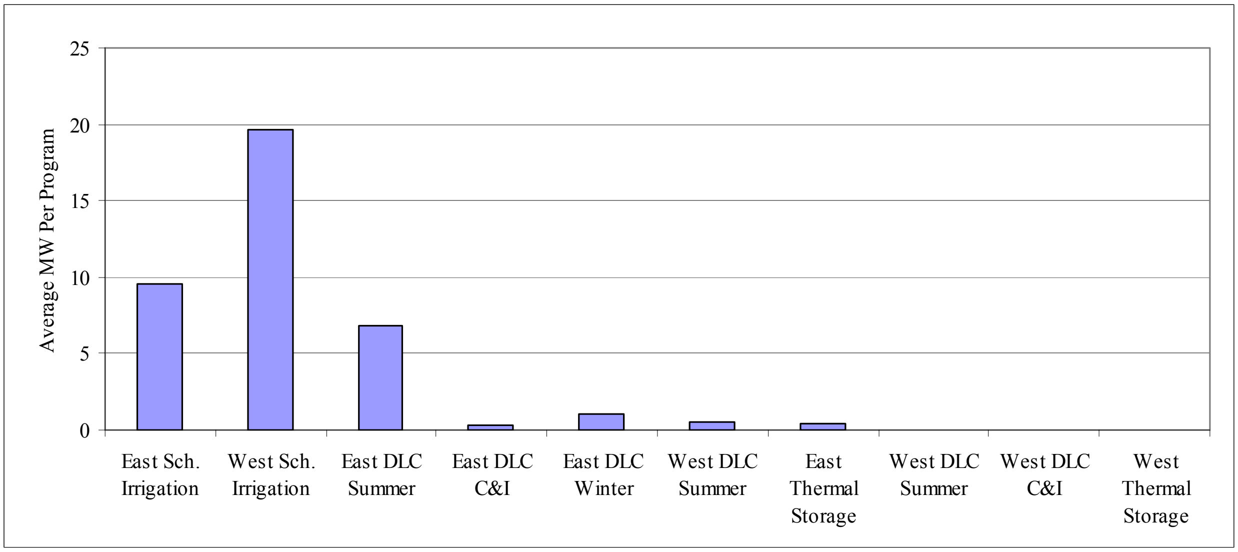


Figure 7.7 – Class 1 DSM Average Megawatts for Alternative Future Scenarios, 2007-2016



Based on these CEM results, and assuming a generic two or three-year phase-in period, Table 7.15 shows the Class 1 DSM resource addition schedule for each of the risk analysis portfolios.[54]

Table 7.15 – Class 1 DSM Cumulative Resource Additions for Candidate Portfolios

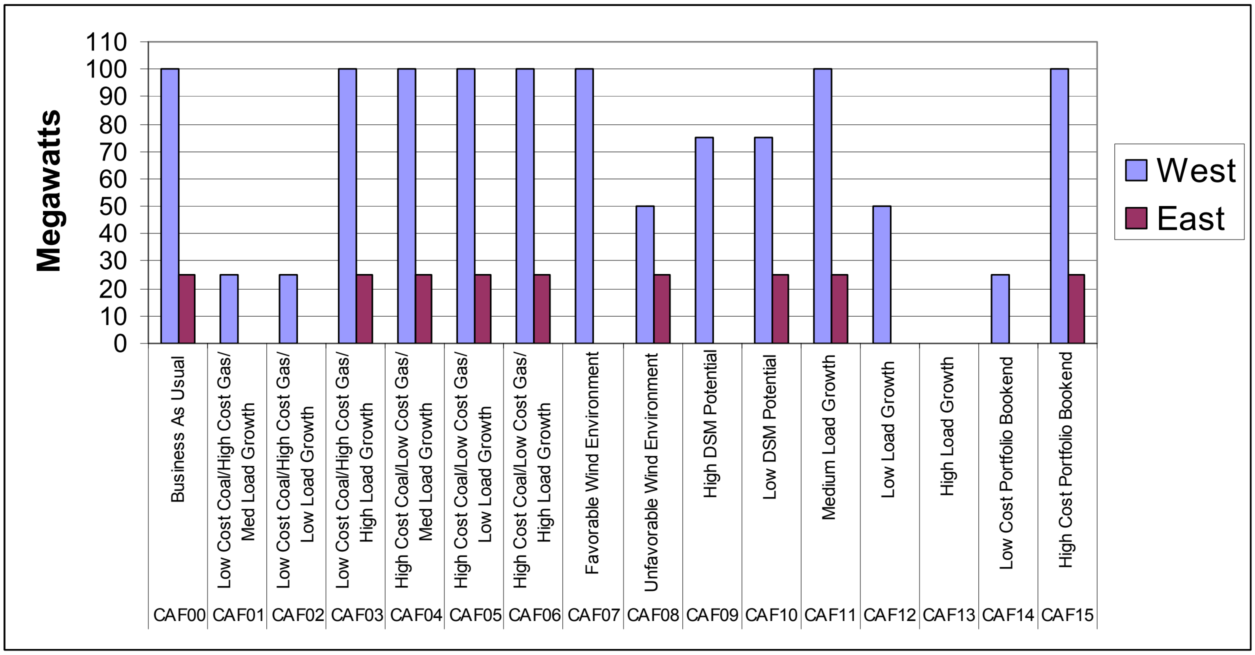
Class 1 DSM Program	Location	Annual Cumulative Megawatt Additions (at the customer meter)			
		2010	2011	2012	2013
Summer Direct Load Control	East		16	32	48
Irrigation Control	East		8	15	
Irrigation Control	West	11	21	32	

Combined Heat and Power Resources

A fixed megawatt amount of combined heat and power (CHP) resources were included in all risk analysis portfolios based on a review of CHP addition patterns for the alternative future scenarios. Figure 7.8 shows the megawatts selected in each of the scenarios by location. (Note that the CHP resource included in the CEM was the 25-megawatt gas-fired topping cycle unit.) The most common resource selection pattern was 125 megawatts (100 megawatts installed in the west side and 25 megawatts installed in the east side), which occurred for seven of the 16 scenarios. The average quantity selected for all scenarios was 90 megawatts. For 11 out of the 16 scenarios, the CHP capacity was added in 2012. Based on these results, PacifiCorp chose a CHP resource investment schedule consisting of three 25-megawatt CHP units in the west in 2012 and one 25-megawatt CHP facility in the east control area in 2012.

[54] Selection of DSM programs or any other resource type for the candidate portfolios should not be construed as meaning that PacifiCorp is limiting program procurement in any way. Similarly, the resource additions schedule, including the phase-in period, is not indicative of the pace of actual program implementation once PacifiCorp identifies cost-effective programs through its procurement process.

Figure 7.8 – CHP Quantities Selected for Each Alternative Future Scenario, 2007-2016



<u>Alternative Resource Strategies</u>

The original 12 risk analysis portfolios were developed according to five resource strategies. These portfolios are distinguished by the planning reserve margin level and the quantity and timing of wind, front office transactions, pulverized coal, and IGCC resources included. The five resource strategies are summarized below.

- Reduce CO_2 cost risk by deferring coal plants until low CO_2-emitting coal options with carbon sequestration are commercially proven (such as IGCC or pulverized coal with chill ammonia CO_2 removal)[55], or eliminating them as a resource option altogether.
- Reduce electricity market price risk by eliminating long-term reliance on front office transactions after 2011, the year that PacifiCorp's system becomes significantly capacity-short.
- Acquire additional wind resources above the amount contained in the initial wind investment schedule described above.
- Plan to a 12 percent planning reserve margin to reduce the risk of having excess generation capacity in the event that expected load growth does not materialize.
- Acquire base load coal resources in the near term to hedge against high gas and electricity prices and price volatility.

[55] This strategy is what the Oregon PUC calls a "coal plant delay scenario". It relies primarily on gas resources and market purchases to address any resource gaps until IGCC is available. (See OPUC IRP Acknowledgement Order, LC-39, Order No. 06-029, p. 51.)

Table 7.16 outlines the specifications for the 12 risk analysis portfolios (labeled RA1 through RA12), and presents the design rationale for each.

The CEM scenario definitions for the risk analysis portfolios include the "medium" forecast values for CO_2 costs, gas/electricity prices, load growth, RPS generation requirements, production tax credit availability, and DSM potential. Nevertheless, the risk analysis portfolios emulate many of the other scenario conditions modeled for the alternative future studies. For example, RA6, which entails removal of pulverized coal as an option, is representative of the coal resource outcome of the three alternative future scenarios based on high coal costs and low gas costs (CAF04, CAF05, and CAF06).

Table 7.16 – Risk Analysis Portfolio Descriptions (Group 1)

ID	Description	Design Rationale
RA1	"Medium" alternative future portfolio, with wind, DSM, and CHP at fixed levels and front office transactions capped at quantities assumed for the 2004 IRP	By virtue of having the fewest constraints on resource choice, it serves as a performance benchmark and starting point for development of the other 11 portfolios.
RA2	RA1 with front office transactions removed as a resource option from 2012 onward (long-term asset-based portfolio)	Tests the strategy of eliminating the use of short-term market purchases (front office transactions) to meet long-term resource needs, and thereby reduce exposure to electricity market price risk.
RA3	RA1 with an additional 600 MW of wind added into the portfolio	Tests the strategy of using incremental amounts of wind to reduce CO_2, fuel, and market price risks.
RA4	RA2 with 12% planning reserve margin and front office transactions removed as a resource option from 2012 onward (long-term asset-based portfolio)	Represents a variant of the "long-term asset-based" portfolio (RA2), but with the lower planning reserve margin to determine the associated cost/risk tradeoff.
RA5	RA2 with the model constrained to select a second Utah pulverized coal plant in 2013 and an east-side IGCC in 2014. Front office transactions are removed as a resource option from 2012 onward (long-term asset-based portfolio)	Tests the relative economics and risk of building coal early as a hedge against gas and electricity market price risk; the IGCC plant replaces an east-side gas plant.
RA6	RA1 with pulverized coal removed as a resource option	Tests the strategy of reducing CO_2 cost risks, as well as testing the risk impact of relying on higher variable cost, shorter lead-time resources until IGCC is commercially ready (i.e., gas-fired generation and market purchases).
RA7	RA2 with 600 MW of additional wind as in RA3 and front office transactions removed as a resource option from 2012 onward (long-term asset-based portfolio)	Tests additional wind in combination with the construction pattern resulting from limiting front office transactions.
RA8	RA1 with a 12% planning reserve margin	Tests the medium alternative future portfolio (RA1) with the lower 12% planning reserve margin.
RA9	RA8 with the model restricted to select Wyoming IGCC plants in 2013 and 2016	Tests an IGCC-intensive portfolio at the lower planning reserve margin level, assuming that the technology is commercially mature enough to acquire by 2013.
RA10	RA9 with a 15% planning reserve margin	Creates a version of RA9 that parallels others with the higher 15% planning reserve margin. Recommended by an IRP public stakeholder at the October 31, IRP public meeting.

ID	Description	Design Rationale
RA11	RA3 (600 MW additional wind and front office transactions included) with the model restricted to select gas resources in 2012 and 2013 and an IGCC resource in 2014	Tests the strategy of reducing CO_2 cost risks with additional wind and restrictions on pulverized coal builds, as well as testing the risk impact of relying on gas resources and front office transactions to address resource deficits until an IGCC resource is acquired in 2014.[56]
RA12	RA11 with a 12% planning reserve margin	Creates a version of RA11 that parallels others with the lower 12% planning reserve margin. See the previous footnote.

The CEM was allowed to optimize the timing of all resources, subject to the following conditions. First, the earliest in-service dates for resources reported in Chapter 5 (Table 5.1, East Side Supply-Side Resource Options) were observed with the exception of the Wyoming supercritical pulverized coal (SCPC) plant. Based on a more recent assessment of the acquisition timeline for this resource, the earliest in-service date was changed from 2013 to 2014 in the model. (Also note that the first Utah SCPC resource was modeled at 340 megawatts rather than the 600 megawatts reported in the Supply-Side Resource Options table to reflect a project scale similar to the Intermountain Power Project Unit 3 (IPP 3). This unit is thus referenced as the "small Utah SCPC resource.") Second, the timing of wind, class 1 DSM, and CHP was fixed according to the pre-defined investment schedules described earlier in the chapter.

Running the CEM for each of the 12 risk analysis portfolios resulted in a unique set of generating and transmission resources and timing patterns. Resource selections for 2012–2014 are profiled below.

- 2012 resources
  - The small Utah SCPC resource was selected in 10 of the 12 portfolios, or 9 of the 11 for which pulverized coal was not excluded as a model option
  - The east single-cycle combustion turbine (SCCT) frame was selected in 9 of the 12 portfolios
  - The east combined cycle combustion turbine (CCCT) was selected in 5 of the 12 portfolios
  - The west SCCT frame was selected in 10 of the 12 portfolios
  - The west CCCT was selected in 4 of the 12 portfolios
- 2013 and 2014 resources
  - The first Wyoming SCPC resource was selected in 6 of the 12 portfolios (replaced by IGCC in one and not allowed in another)
  - Only one gas resource was selected for 2013; all others were selected for 2012

Table 7.17 shows generation (coal and gas) and transmission resource additions for each of the risk analysis portfolios by general location and year.

[56] This portfolio, requested for study by OPUC staff, addresses the OPUC's 2004 IRP acknowledgement order mandate to "fully explore whether delaying a commitment to coal until IGCC technology is further commercialized is a reasonable course of action." (Order No. 06-029, p. 51)

Table 7.17 – Generation and Transmission Resource Additions

	Resource	RA1	RA2	RA3	RA4	RA5	RA6	RA7	RA8	RA9	RA10	RA11	RA12
Coal	Small Utah SCPC (340 MW)	2012	2012	2012	2012	2012	-	2012	2012	2012	2012	2018	-
	Large Utah SCPC (600 MW)	2017	2018	2018	2018	2013	-	2018	2017	2018	2018	2018	2018
	Wyoming SCPC 1 (750 MW)	2013	2013	2015	2013	2013	-	2014	2014	2017	2017	2015	2016
	Wyoming SCPC 2 (750 MW)	2018	2018	2018	2018	2018	-	2018	2018	-	-	2018	2018
	West IGCC (200 MW)	2016	2017	2017	2016	2018	2016	2017	2018	2018	2018	2018	2018
	West IGCC (300 MW)	2018	2017	2018	2017	2018	2018	2017	2018	2018	2018	2018	2018
	Wyoming IGCC 1 (497 MW)	-	-	-	-	2014	2016	-	-	2013	2013	2014	2014
	Wyoming IGCC 2 (497 MW)	-	-	-	-	-	2017	-	-	2016	2016	-	-
	Utah IGCC 1 (497 MW)	-	-	-	-	-	2018	-	-	-	-	-	-
	Utah IGCC 2 (497 MW)	-	-	-	-	-	2018	-	-	-	-	-	-
Gas	West SCCT Frame (332 MW)	2012	2012	2012	2012	2012	2013	2012	-	-	2012	2012	2012
	West CCCT F 2x1 w/DF (602 MW)	-	2012	-	-	2012	-	2012	-	-	-	-	-
	West CCCT G 1x1 w/DF (392 MW)	-	-	-	2012	-	-	-	-	-	-	-	-
	East SCCT Frame (302 MW)	-	2012	2012	2012	2012	2012	2012	2012	-	-	2012	2012
	East CCCT F 2x1 w/DF (548 MW)	-	2012	-	-	2012	2012	2012	-	-	-	-	-
	East CCCT G 1x1 w/DF (357 MW)	-	-	-	2012	-	-	-	-	-	-	-	-

	RA1	RA2	RA3	RA4	RA5	RA6	RA7	RA8	RA9	RA10	RA11	RA12
Front Office Transactions Ave Annual MW, 2012-2016	1,063	-	1,005	-	-	1,024	-	1,000	1,115	1,097	1,009	863
Planning Reserve Margin	15%	15%	15%	12%	15%	15%	15%	12%	12%	15%	15%	12%

Transmission Project	RA1	RA2	RA3	RA4	RA5	RA6	RA7	RA8	RA9	RA10	RA11	RA12
West Main-Walla Walla (630 MW)	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012
Walla Walla-Yakima B (400 MW)	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012	2012
Mona-Utah North (500 MW increments)	2012 x1	2018 x1	2012 x1	2018 x1	2018 x1	2018 x1	2018 x1	2018 x1	2018 x1	2012 x2	-	-
Jim Bridger-Ben Lomond (500 MW increments)	2015 x2	2016 x2	2016 x2	2016 x2	2014 x2	2014 x1	2014 x2	2016 x2	2015 x2	2016 x2	2015 x2	2016 x3
Utah North-West Main (500 MW increments)	2018 x1	2018 x1	2018 x1	2018 x1	2014 x1	2018 x1	2018 x1	2018 x1	2017 x1	2017 x1	2018 x1	2018 x1
Wyoming-Bridger (500 MW increments)	-	-	2018 x1	-	2018 x1	-	-	-	2018 x3	2015 x1	2018 x1	2018 x1
Path-C Upgrade B[57] (600 MW)	-	-	-	-	-	2018	-	-	-	-	-	-

STOCHASTIC SIMULATION RESULTS – GROUP 1 PORTFOLIOS

The 12 risk analysis portfolios were run in stochastic simulation mode with varying loads, thermal outages, hydro availability, and electricity and natural gas wholesale prices across 100 itera-

[57] The original Path C upgrade and the Craig Hayden - Utah North transmission projects were treated as fixed assumptions in the CEM.

tions. The sections below show how the portfolios compare to one another on the basis of the stochastic cost, risk, reliability, and emissions measures. The section concludes with a summary portfolio performance assessment, as well as resource selection conclusions that informed the development of the second group of risk analysis portfolios.

Stochastic Mean Cost

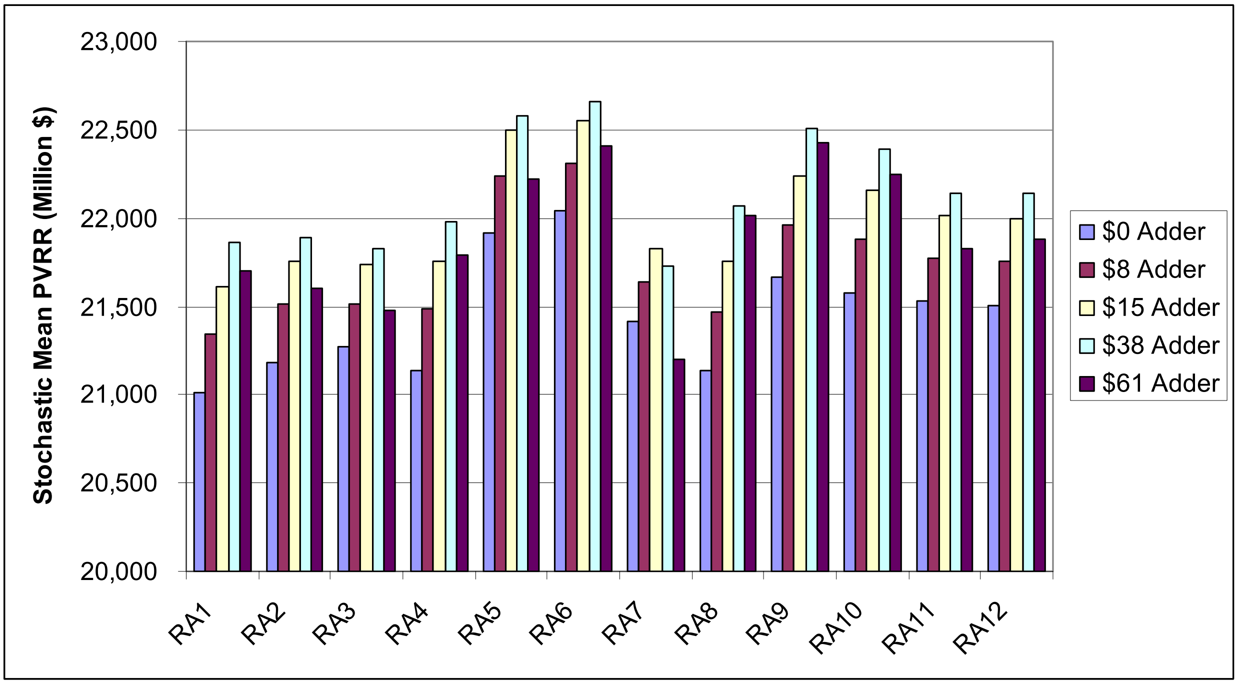
Table 7.18 reports the stochastic mean PVRR for each of the portfolios by CO_2 adder cases, and shows the portfolio rankings based on the PVRR average across the five adder cases. Portfolio RA1 has the lowest average PVRR, followed by RA7 and RA3. In contrast, RA5 and RA6 have the highest average PVRRs.

Table 7.18 – Portfolio Cost by CO_2 Adder Case

ID	Stochastic Mean PVRR (Million $)						Rank
	$0 Adder (2008$)	$8 Adder (2008$)	$15 Adder (2008$)	$38 Adder (2008$)	$61 Adder (2008$)	Average	
RA1	21,016	21,346	21,614	21,865	21,706	21,509	1
RA2	21,183	21,514	21,758	21,893	21,601	21,590	4
RA3	21,269	21,515	21,740	21,827	21,482	21,567	3
RA4	21,140	21,489	21,753	21,975	21,789	21,629	5
RA5	21,921	22,238	22,496	22,583	22,225	22,292	11
RA6	22,042	22,313	22,548	22,658	22,411	22,394	12
RA7	21,414	21,642	21,829	21,732	21,200	21,563	2
RA8	21,140	21,472	21,758	22,072	22,018	21,692	6
RA9	21,663	21,964	22,242	22,510	22,423	22,160	10
RA10	21,573	21,882	22,158	22,392	22,244	22,050	9
RA11	21,529	21,769	22,019	22,139	21,827	21,857	8
RA12	21,505	21,754	21,999	22,143	21,881	21,856	7

Figure 7.9 shows the progression of each portfolio's stochastic cost as the CO_2 adder increases. For most of the portfolios, the cost peaks at the $38 adder level, and then declines at the $61 adder level. This cost behavior is driven by the influence of CO_2 allowance trading activity in the studies' out-years, where a significant amount of allowance credits are realized.

Figure 7.9 – Stochastic Mean Cost by CO_2 Adder Case



It is noteworthy that the CEM's deterministic portfolio solution without resource restrictions—Portfolio RA1—also has the lowest stochastic cost. Table 7.19 summarizes the cost impact of constraining CEM-selected resources in the reference portfolio according to the resource strategies defined for the other portfolios. The average PVRRs for the five CO_2 adder cases is used as the cost impact measure.

Table 7.19 – Cost Impact of Portfolio Resource Strategies

ID	Resource Strategy Modeled in the CEM	Cost Impact Relative to Portfolio RA1 Ave. Stochastic Mean PVRR for CO_2 adder cases (Million $)
RA1	Reference Case: no resource constraints (FOT capped at 1200 MW)	-
RA2	Remove FOT as a resource option after 2011	81
RA3	Additional wind	57
RA4	Plan to a 12% PRM and remove FOT after 2011	120
RA5	Early SCPC and force IGCC in 2014	783
RA6	Remove SCPC as a resource option	885
RA7	Additional wind and remove FOT after 2011	54
RA8	Plan to a 12% PRM	183
RA9	Force IGCC in 2013 and 2016	651
RA10	Force IGCC in 2013 and 2016; plan to 12% PRM	540
RA11	Additional wind; exclude SCPC for 2012-13 and force IGCC in 2014	348
RA12	Same as RA11 but plan to a 12% PRM	347

As shown in the table, constraining the coal resources has the largest impact. Removing super-critical pulverized coal increases portfolio cost by $885 million relative to the RA1 portfolio. Portfolios with a 15 percent planning reserve margin that involved restricting the CEM to select IGCC in certain years (RA5, RA10, and RA11) averaged $557 million higher. The average cost increase for all the portfolios relative to RA1 was $368 million.

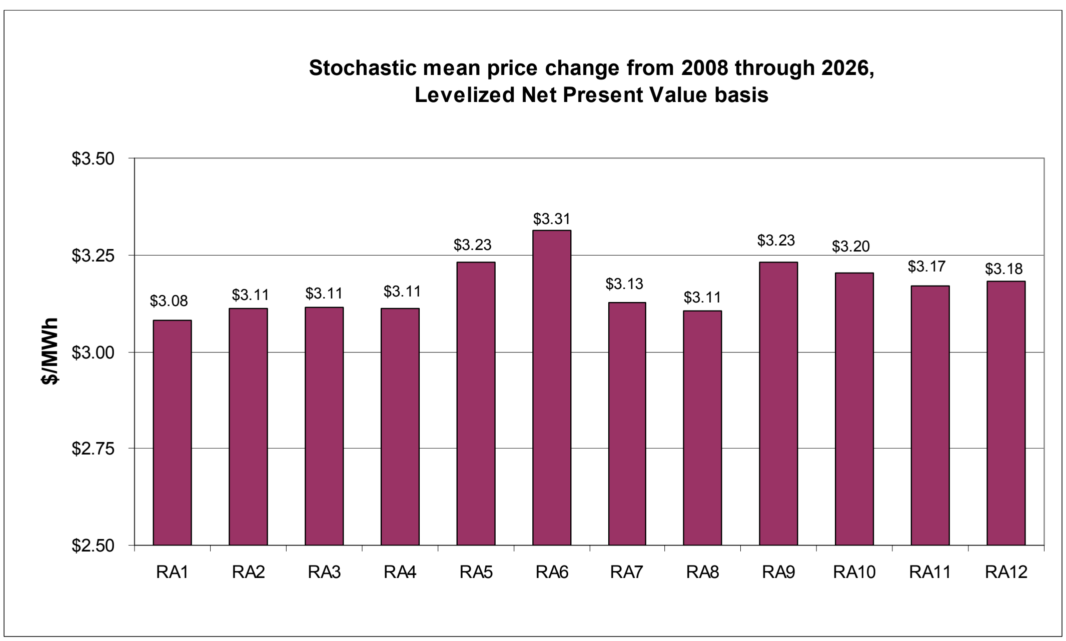
Other observations concerning the relationship between portfolio cost and resource mix and timing include the following.

- Building coal resources earlier or later than recommended by the CEM increases stochastic cost.
- Lowering the planning reserve margin increases stochastic PVRR due to the costs associated with higher Energy Not Served. Rather than reducing investment in base load plants to meet the lower load obligation, the CEM chooses to defer them.
- Acquiring the additional 600 megawatts of wind increases stochastic cost, although the amount is smaller than for the other resource strategies.
- Removing front office transactions after 2011 increases stochastic cost.

Customer Rate Impact

Figure 7.10 shows the customer rate impact of each portfolio.[58] The rate impact measure is the change in the customer dollar-per-megawatt-hour price from 2008 through 2026 due to the portfolio resources, expressed on a levelized net present value basis. As indicated, RA1 has the smallest rate change at $3.08/MWh. RA6, which has no pulverized coal plants, has the highest at $3.31/MWh.

Figure 7.10 – Customer Rate Impact



[58] The revenue requirement calculated by the CEM uses a real levelized capital charge.

Emissions Externality Cost

PacifiCorp calculates the emissions externality cost as the increase in stochastic mean PVRR relative to the \$0 adder case for each CO_2 adder level. This externality cost measure captures (1) the increased variable operating costs for fossil fuel generation, (2) the system re-dispatch impact attributable to the cost adders, and (2) the net present value of the sum of the annual CO_2 allowance trading balances for 2007–2026. The externality costs are reported in Table 7.20 along with portfolio rankings based on the average of the incremental costs for the four adder levels. These cost estimates assume a cap-and-trade compliance strategy.

Portfolio RA7 performs the best with an average externality cost of \$187 million. RA8 had the highest cost at \$690 million. All the portfolios that included the extra wind—RA3, RA7, RA11, and RA12—had the lowest costs. In contrast, portfolios built according to the lower 12-percent planning reserve margin had the highest externality costs (RA8 and RA9). The lower reserve margin results in higher coal resource utilization to keep the system balanced.

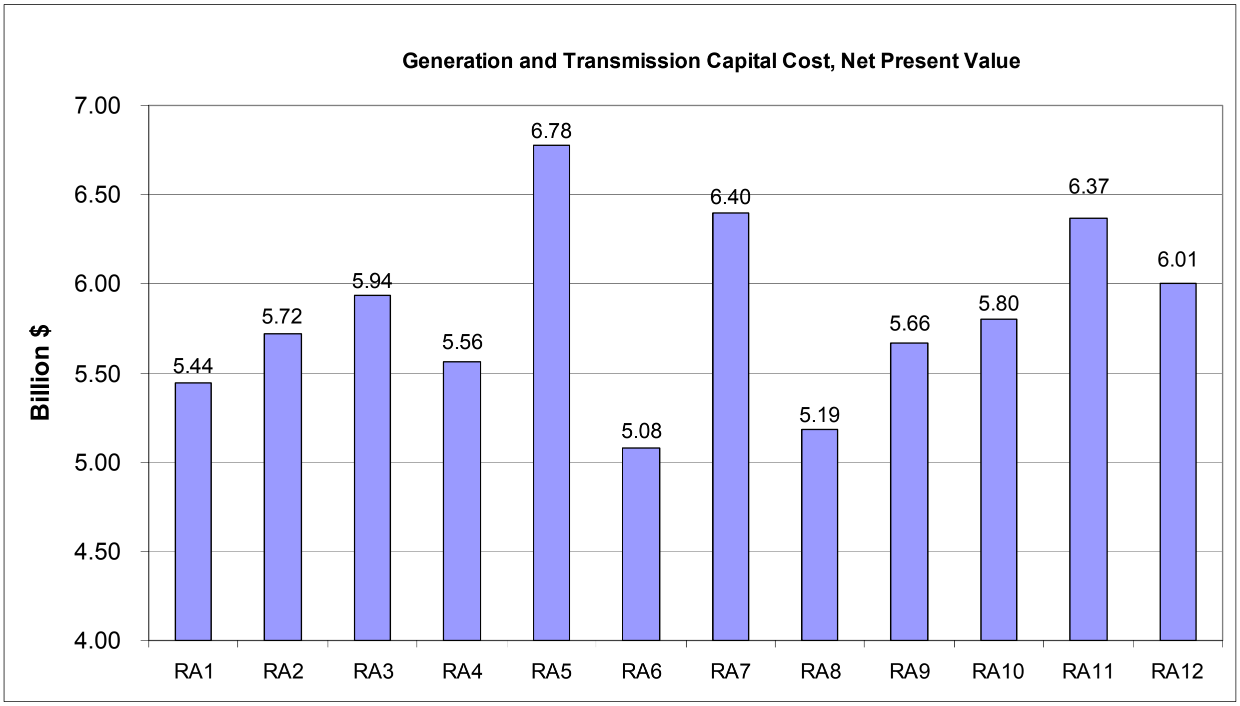
Table 7.20 – Portfolio Emissions Externality Cost by CO_2 Adder Level

	Incremental Stochastic Mean PVRR by CO_2 Adder (Million \$)						
	CO_2 Adder Level (2008\$)						
ID	\$0	\$8	\$15	\$38	\$61	Average	Rank
RA1	-	330	598	849	690	617	10
RA2	-	331	575	710	417	508	7
RA3	-	246	471	558	213	372	2
RA4	-	349	613	835	649	612	9
RA5	-	317	575	662	304	465	6
RA6	-	271	506	616	369	441	5
RA7	-	228	415	318	-214	187	1
RA8	-	332	618	932	878	690	12
RA9	-	301	579	847	760	622	11
RA10	-	309	585	819	672	596	8
RA11	-	240	490	610	298	410	3
RA12	-	249	494	638	375	439	4

Capital Cost

Figure 7.11 shows the total capital cost for each portfolio, expressed on a net present value of the sum of all capital costs accrued for 2007–2026. As expected, RA5 with its relatively larger coal plant investment schedule and earlier in-service dates exceeds all others at \$6.78 billion. In contrast RA6—with no coal resources until 2016—has the lowest capital cost at \$5.08 billion. The average capital for all portfolios is \$5.83 billion.

Figure 7.11 – Total Capital Cost by Portfolio



Stochastic Risk Measures

Tables 7.21 and 7.22 report the stochastic risk results for each of the 12 risk analysis portfolios. Table 7.21 shows risk exposure and standard deviation (production cost) averaged across the five CO_2 adder cases, as well as the portfolio rankings for these two measures. Table 7.22 shows the detailed statistics for each CO_2 adder case, and also includes fifth-percentile PVRR and ninety-fifth-percentile PVRR results.

Table 7.21 – Average Risk Exposure and Standard Deviation for CO_2 Adder Cases

	Risk Exposure (Million $)	Rank	Standard Deviation (Million $)	Rank
ID	Average Across CO_2 Adder Cases			
RA1	41,928	6	13,246	6
RA2	41,217	4	13,015	4
RA3	41,690	5	13,149	5
RA4	42,245	7	13,324	7
RA5	36,706	1	11,891	1
RA6	47,588	12	14,666	12
RA7	39,856	2	12,658	2
RA8	43,287	11	13,581	11
RA9	42,784	9	13,503	9

ID	Risk Exposure (Million $)	Rank	Standard Deviation (Million $)	Rank
	Average Across CO_2 Adder Cases			
RA10	42,247	8	13,337	8
RA11	39,950	3	12,771	3
RA12	42,952	10	13,576	10

Table 7.22 – Risk Measure Results by CO_2 Adder Case (Million $)

ID	Risk Exposure	Standard Deviation	5th Percentile	95th Percentile	Upper-Tail Mean
$0 CO_2 Adder (2008$)					
RA1	34,879	9,837	14,258	34,111	55,894
RA2	34,096	9,608	14,504	33,989	55,279
RA3	34,654	9,753	14,553	34,404	55,923
RA4	35,063	9,886	14,355	34,358	56,203
RA5	29,837	8,544	15,819	33,286	51,758
RA6	39,971	11,060	14,221	36,155	62,013
RA7	32,900	9,313	14,968	34,007	54,315
RA8	36,192	10,154	14,014	34,725	57,332
RA9	35,783	10,097	14,699	35,608	57,445
RA10	35,210	9,939	14,862	35,075	56,783
RA11	33,101	9,411	14,988	34,596	54,630
RA12	35,860	10,130	14,588	35,370	57,366
$8 CO_2 Adder (2008$)					
RA1	37,651	10,690	12,770	35,895	58,997
RA2	36,957	10,484	12,974	35,812	58,471
RA3	37,419	10,602	12,900	36,099	58,934
RA4	37,923	10,761	12,691	36,176	59,412
RA5	32,538	9,377	13,987	35,148	54,776
RA6	43,026	11,992	12,892	37,837	65,339
RA7	35,683	10,166	13,061	35,730	57,326
RA8	38,949	11,008	12,824	36,481	60,420
RA9	38,493	10,936	13,501	37,326	60,457
RA10	37,974	10,787	13,313	36,817	59,856
RA11	35,759	10,236	13,264	36,279	57,258
RA12	38,638	10,984	13,001	37,029	60,391
$15 CO_2 Adder (2008$)					
RA1	39,161	13,006	12,185	37,049	60,775
RA2	38,449	12,737	12,340	36,953	60,207
RA3	38,920	12,899	12,328	37,208	60,660
RA4	39,432	13,053	12,232	37,327	61,186
RA5	33,965	11,628	13,575	36,329	56,461
RA6	44,615	14,400	12,701	38,930	67,163
RA7	37,149	12,394	12,688	36,822	58,978

ID	Risk Exposure	Standard Deviation	5th Percentile	95th Percentile	Upper-Tail Mean
RA8	40,469	13,332	12,361	37,624	62,226
RA9	39,980	13,270	12,990	38,470	62,221
RA10	39,479	13,103	12,800	37,967	61,637
RA11	37,215	12,541	12,953	37,428	59,234
RA12	40,127	13,340	12,544	38,142	62,126
$38 CO_2 Adder (2008$)					
RA1	45,344	15,106	10,304	40,944	67,209
RA2	44,675	14,873	10,218	40,799	66,568
RA3	45,113	15,004	10,315	40,962	66,940
RA4	45,733	15,202	10,249	41,207	67,708
RA5	40,037	13,728	11,554	39,967	62,620
RA6	51,296	16,633	9,933	42,604	73,953
RA7	43,247	14,487	10,371	40,489	64,979
RA8	46,741	15,455	10,211	41,521	68,813
RA9	46,206	15,369	10,878	42,278	68,716
RA10	45,674	15,193	10,975	41,781	68,066
RA11	43,311	14,616	11,019	41,334	65,451
RA12	46,418	15,465	10,586	41,935	68,561
$61 CO_2 Adder (2008$)					
RA1	52,604	17,593	6,398	44,741	74,310
RA2	51,911	17,372	6,453	44,526	73,511
RA3	52,345	17,487	6,203	44,627	73,826
RA4	53,076	17,720	6,267	44,987	74,865
RA5	47,152	16,176	7,941	43,024	69,377
RA6	59,029	19,245	6,505	46,249	81,440
RA7	50,298	16,931	6,105	43,972	71,498
RA8	54,084	17,956	6,452	45,323	76,102
RA9	53,459	17,843	7,121	45,995	75,883
RA10	52,896	17,663	7,112	45,514	75,141
RA11	50,365	17,052	6,989	45,086	72,193
RA12	53,717	17,963	6,559	45,628	75,597

Portfolio RA5 has the smallest average risk exposure due to the early addition of coal capacity. Other resource strategies that lower risk exposure include (1) increasing wind capacity, (2) eliminating or reducing reliance on market purchases, and (3) planning to a 15% reserve margin rather than 12%. For example, by comparing RA3 with RA1, the 600 megawatts of additional wind is shown to reduce risk exposure by an average of $238 million across the five CO_2 adder scenarios. The risk reduction benefit increases at successfully higher CO_2 adder levels ($224 million under the $0 adder to $260 million under the $61 adder). The benefit of reducing reliance on front office transactions after 2011 is evident from comparing portfolio RA2 with RA1. The average risk exposure decreases by an average of $711 million. Combining both extra wind and eliminating front office transactions after 2011 (RA7) decreases average risk exposure by $2.1

billion. Changing the planning reserve margin strategy (RA8) has a large impact on risk exposure: going from a 12% to 15% margin reduces average risk exposure by $1.4 billion.

In contrast to the risk exposure reduction strategies, removing pulverized coal as a resource option (RA5) increases average risk exposure by $5.7 billion. At the $61 CO_2 adder level, the risk exposure for RA6 reaches a high of $6.4 billion.

Cost/Risk Tradeoff Analysis

The three figures below are scatter plots of portfolio cost (PVRR) and risk exposure, and illustrate the tradeoff between the two performance measures. Figure 7.12 plots the average PVRR and risk exposure across the CO_2 adder cases. Figure 7.13 shows the cost-risk relationship for the $0 CO_2 adder case, while Figure 7.14 shows the relationship for the $61 CO_2 adder case (representing the CO_2 scenario risk bookends).

The figures show that when considering exposure to potential high-cost outcomes, RA5 has the lowest portfolio risk regardless of the CO_2 adder level. However, when considering the balance between risk and cost, RA7 and RA1—and RA2 and RA3 right behind—perform the best among this portfolio set. Under the high CO_2 adder case, portfolio RA7 dominates the others by a significant amount.

Figure 7.12 – Average Stochastic Cost versus Risk Exposure

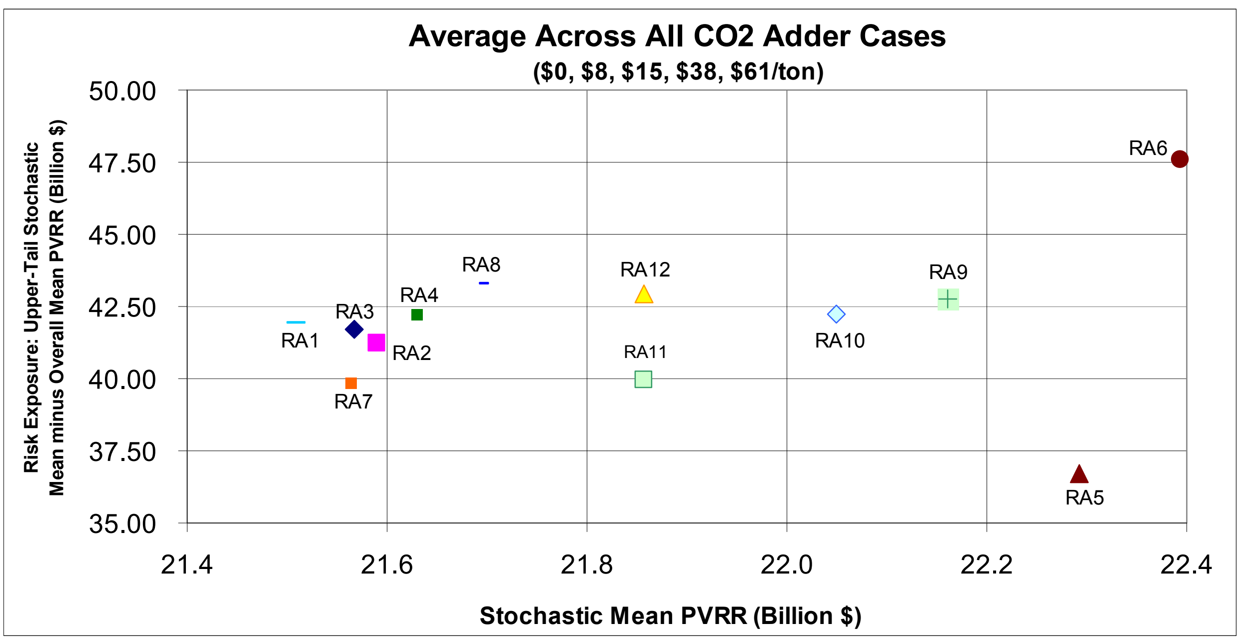


Figure 7.13 – Stochastic Cost versus Risk Exposure for the \$0 CO_2 Adder Case

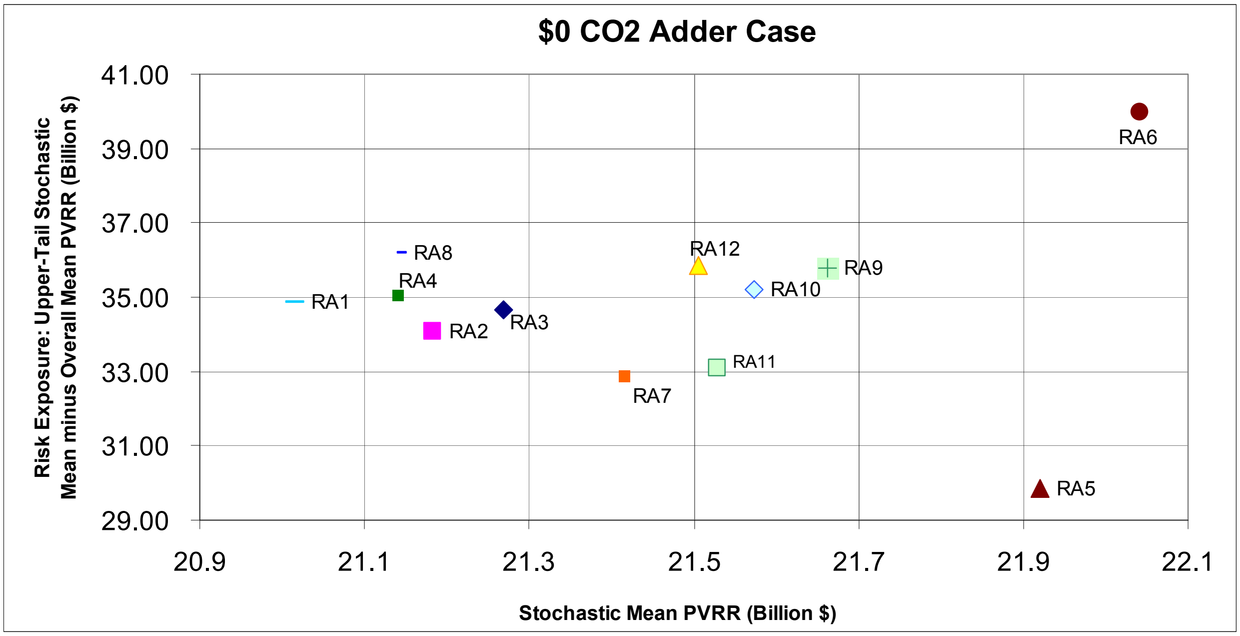
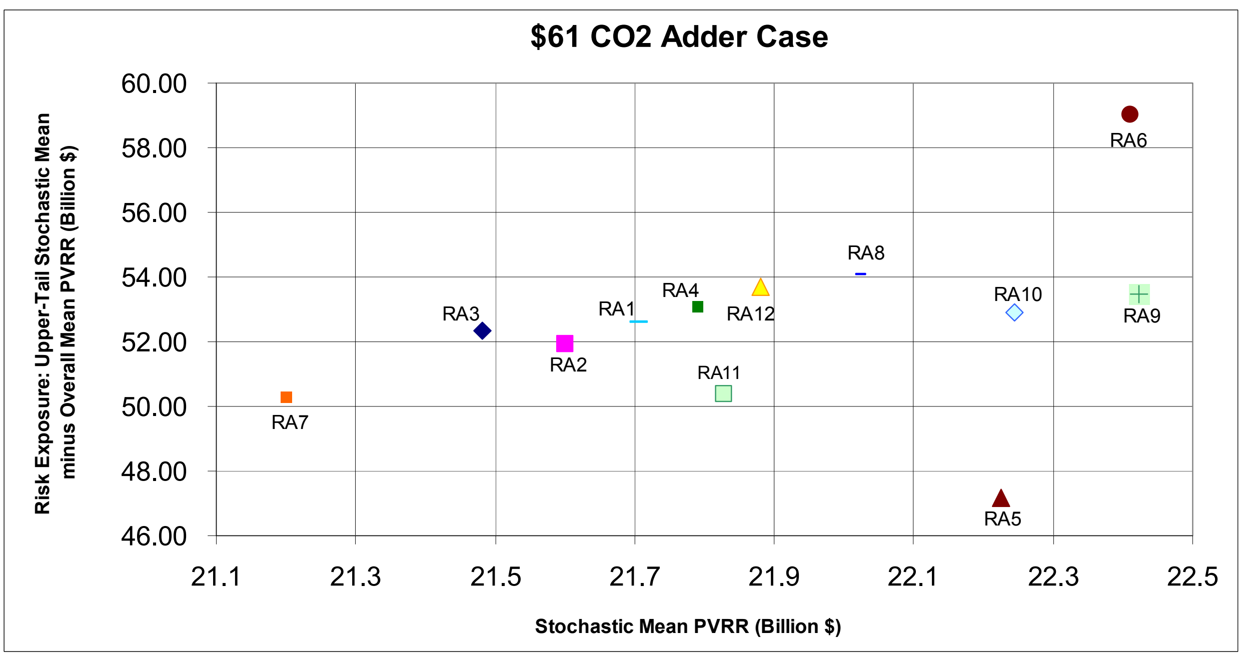


Figure 7.14 – Stochastic Cost versus Risk Exposure for the \$61 CO_2 Adder Case



As far the resource strategies go, increasing wind capacity and reducing reliance on market purchases promotes a better balance of portfolio cost and risk. In contrast, eliminating pulverized coal yields the worst cost-risk balance in all cases; this strategy yields a portfolio with both higher-risk and higher-cost resources.

Resource Strategy Risk Reduction

As described above, adding constraints to the reference portfolio results in a higher stochastic cost. Nevertheless, it can be desirable to choose portfolios or resource strategies that may be sub-optimal on the basis of expected stochastic cost, but that reduce risk exposure.

Several risk analysis portfolios were developed to evaluate the cost versus risk exposure implications of specific resource strategies. These resource strategies and the associated test portfolios are summarized in Table 7.23.

Table 7.23 – Resource Strategies and Test Portfolios for Cost-Risk Exposure

Resource Strategy	Test Portfolio
Eliminate market purchases after 2012 to reduce electricity market price risk	RA2
Include additional wind (600 MW) to reduce CO_2, fuel and market price risks	RA3
Lower the planning reserve margin from 15% to 12% to reduce portfolio investment costs	RA8
Remove pulverized coal plants as an option and fill the capacity gap with other resources	RA6

At issue is whether the resource strategies increase or decrease risk exposure relative to the reference portfolio, and by how much. If an extra dollar of PVRR spent on the resource strategy translates into more than a dollar in risk exposure reduction, then the extra portfolio cost could be considered a worthwhile insurance investment for customers. Comparing the PVRR and risk exposure at the $61 CO_2 adder level in these terms yields the following conclusions:

- **Eliminate market purchases after 2012 (RA2)** – this resource strategy lowers total risk exposure; the relative reduction is $4.15 for every additional PVRR dollar spent
- **Include an additional 600 megawatts of wind (RA3)** – this resource strategy lowers total risk exposure marginally; the relative reduction is $1.03 for every additional PVRR dollar spent
- **Lower the planning reserve margin from 15% to 12% (RA8)** – this resource strategy raises total risk exposure; the relative increase is $11.93 for every additional PVRR dollar spent
- **Remove pulverized coal plants as a resource option (RA6)** – this resource strategy raises total risk exposure; the relative increase is $6.26 for every additional PVRR dollar spent

Carbon Dioxide and Other Emissions

The following tables and figures profile the CO_2 emissions footprint for the risk analysis portfolios, as well as for SO_2, NO_X, and mercury (Hg). For CO_2 emissions, results are shown by CO_2 adder level and for two periods, 2007–2016 and 2007–2026. The tables also report the separate CO_2 contributions from generators and market purchases (existing long term purchases, front office transactions and spot purchases). Figures 7.15 and 7.16 show how the cumulative CO_2 emission for each portfolio decline as the cost adder is increased.

The resource strategies had the following effect on generator CO_2 emissions relative to the reference portfolio, RA1:

- Removing all pulverized coal plants had the highest emission reduction benefit, lowering the generator CO_2 footprint by 12 million tons for 2007–2016 and 29 million tons for 2007–2026 on average
- Reducing front office transactions had a negligible impact on generator emissions for the first ten years; for 2007–2026, there was a decrease of 7 million tons
- The additional 600 megawatts of wind decreased emissions by 8 million tons for 2007–2016 and 22 million tons for 2007–2026
- Reducing the planning reserve margin from 15% to 12% decreased emissions by 2.5 million tons for 2007–2016, but the overall reduction for 2007–2026 was only 259,000 tons
- The IGCC bridging strategy (RA11) reduced emissions by 9 million tons for 2007–2016 and 14 million tons for 2007–2026

Table 7.24 – Cumulative CO_2 Emissions by Cost Adder Level, 2007-2016

ID	Generator CO_2 Emissions, 2007-2016 (1000 Tons)						Rank
	$0 Adder	$8 Adder	$15 Adder	$38 Adder	$61 Adder	Average	
RA1	520,275	498,032	494,673	488,422	483,805	497,041	9
RA2	522,525	498,785	495,141	488,330	483,052	497,567	10
RA3	511,893	490,290	486,868	480,446	475,651	489,030	4
RA4	523,785	500,658	497,114	490,322	485,150	499,406	12
RA5	526,226	501,006	497,079	488,500	481,903	498,943	11
RA6	507,235	486,289	482,912	476,713	472,093	485,048	1
RA7	515,681	492,030	488,377	481,337	475,995	490,684	5
RA8	516,988	495,680	492,322	486,088	481,439	494,503	8
RA9	515,118	493,741	490,461	484,494	480,148	492,792	6
RA10	517,046	495,287	491,936	485,756	481,329	494,271	7
RA11	511,198	489,590	486,177	479,694	474,732	488,278	3
RA12	509,825	488,734	485,389	479,087	474,398	487,487	2

ID	CO_2 Emissions from Market Purchases, 2007-2016 (1000 Tons)						Rank
	$0 Adder	$8 Adder	$15 Adder	$38 Adder	$61 Adder	Average	
RA1	77,798	85,510	86,358	87,255	87,488	84,882	8
RA2	65,301	73,831	74,758	75,742	76,068	73,140	4
RA3	77,243	76,374	85,408	86,215	86,527	82,353	6
RA4	65,133	73,603	74,517	75,581	75,909	72,949	3
RA5	64,245	73,124	74,144	75,453	76,374	72,668	2
RA6	80,586	87,870	88,673	89,468	89,673	87,254	12
RA7	64,771	73,229	74,117	75,110	75,468	72,539	1
RA8	78,715	86,342	87,195	88,136	88,605	85,799	9
RA9	78,715	87,458	88,341	89,244	89,623	86,676	11
RA10	79,001	86,627	87,511	88,348	88,461	85,990	10
RA11	75,166	82,727	83,578	84,636	85,069	82,235	5
RA12	76,470	83,904	84,761	85,768	86,233	83,427	7

Table 7.25 – Cumulative CO_2 Emissions by Cost Adder Level, 2007-2026

ID	Generator CO_2 Emissions, 2007-2026 (1000 Tons)						Rank
	$0 Adder	$8 Adder	$15 Adder	$38 Adder	$61 Adder	Average	
RA1	1,121,716	1,071,110	1,051,661	1,005,991	983,131	1,046,722	11
RA2	1,118,600	1,065,377	1,044,783	996,976	972,473	1,039,642	7
RA3	1,100,779	1,050,767	1,030,985	983,391	959,728	1,025,130	3
RA4	1,122,432	1,070,823	1,050,931	1,004,604	980,942	1,045,947	10
RA5	1,122,352	1,066,931	1,045,768	993,546	966,702	1,039,060	6
RA6	1,092,590	1,043,019	1,023,626	977,283	954,462	1,018,196	1
RA7	1,098,664	1,045,400	1,024,659	976,320	951,671	1,019,343	2
RA8	1,119,654	1,070,775	1,051,835	1,007,310	985,331	1,046,981	12
RA9	1,117,852	1,068,445	1,049,168	1,004,509	983,189	1,044,632	8
RA10	1,120,216	1,070,065	1,050,497	1,004,820	982,764	1,045,672	9
RA11	1,109,142	1,058,370	1,038,568	990,992	967,452	1,032,905	5
RA12	1,104,925	1,055,091	1,035,617	989,230	966,425	1,030,258	4

ID	CO_2 Emissions from Market Purchases, 2007-2026 (1000 Tons)						Rank
	$0 Adder	$8 Adder	$15 Adder	$38 Adder	$61 Adder	Average	
RA1	146,689	164,207	170,810	180,598	182,578	168,976	8
RA2	134,276	153,061	160,118	170,663	173,411	158,306	2
RA3	147,303	175,981	171,287	182,115	184,159	172,169	11
RA4	136,267	154,743	161,760	172,140	174,792	159,940	4
RA5	133,685	153,044	160,597	172,336	175,981	159,129	3
RA6	152,525	169,071	175,514	184,348	187,453	173,782	12
RA7	131,307	149,820	156,751	167,235	170,350	155,093	1
RA8	149,653	166,984	173,528	182,981	185,322	171,694	10
RA9	149,653	165,141	171,773	182,117	185,321	170,801	9
RA10	145,724	162,544	169,099	179,515	182,473	167,871	5
RA11	145,021	162,764	169,618	180,874	183,689	168,393	6
RA12	145,335	163,064	170,005	181,359	183,821	168,717	7

Figure 7.15 – Generator CO_2 Emissions by Cost Adder Level, Cumulative for 2007-2016

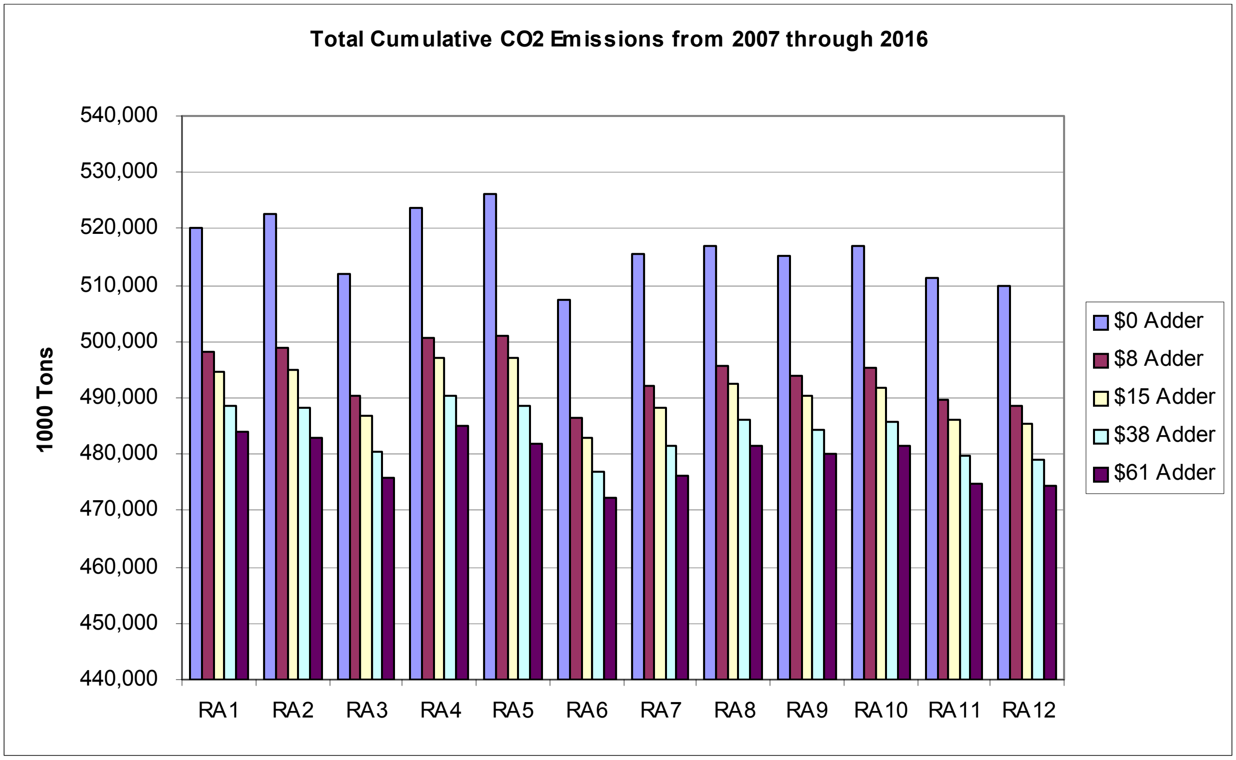


Figure 7.16 – Generator CO_2 Emissions by Cost Adder Level, Cumulative for 2007-2026

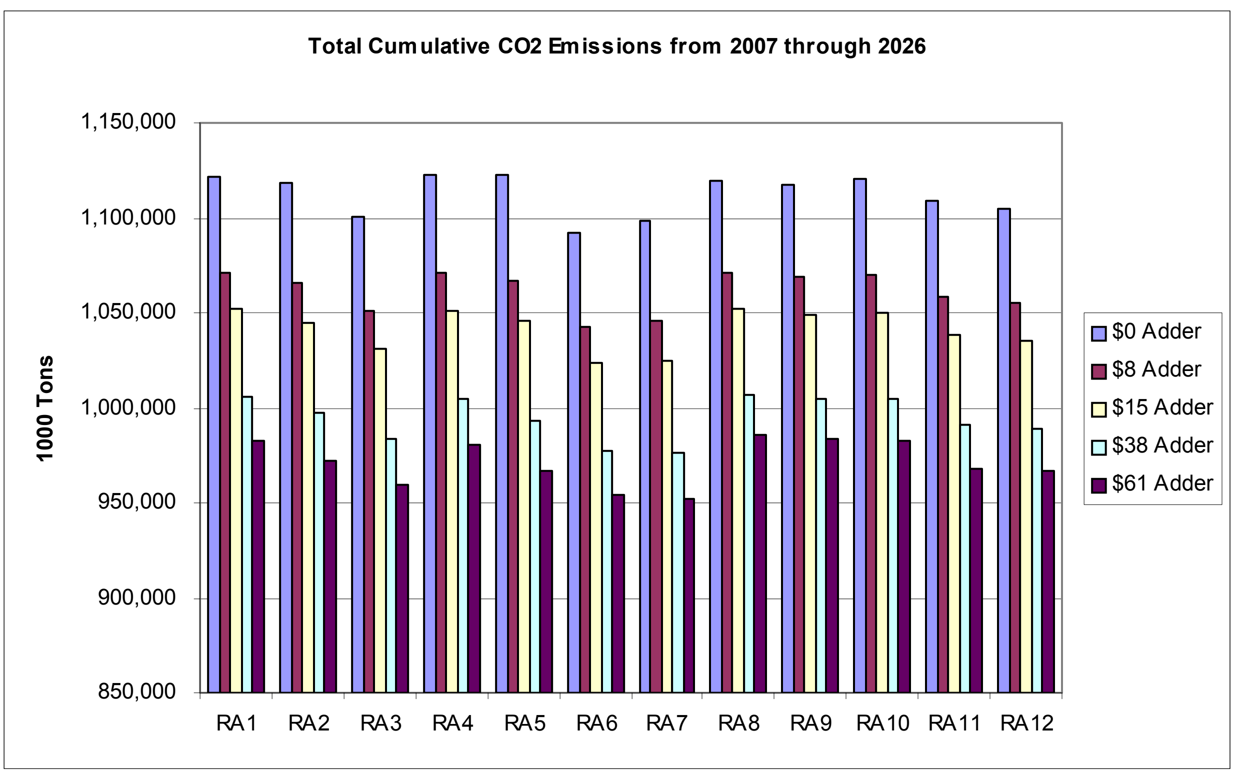


Table 7.26 – System Generator Emissions Footprint, Cumulative Amount for 2007–2026

ID	SO_2 1000 Tons	NO_X 1000 Tons	Hg Pounds	CO_2 1000 Tons	SO_2 1000 Tons	NO_X 1000 Tons	Hg Pounds	CO_2 1000 Tons
	$0 Adder (2008$)				$8 Adder (2008$)			
RA1	822	1,161	8,340	1,121,716	781	1,099	7,560	1,071,110
RA2	814	1,149	8,330	1,118,600	771	1,082	7,860	1,065,377
RA3	817	1,156	8,228	1,100,779	775	1,093	8,060	1,050,767
RA4	821	1,160	8,354	1,122,432	779	1,095	8,040	1,070,823
RA5	796	1,122	8,293	1,122,352	749	1,049	7,953	1,066,931
RA6	792	1,132	7,825	1,092,590	751	1,068	7,560	1,043,019
RA7	805	1,135	8,228	1,098,664	762	1,068	7,985	1,045,400
RA8	827	1,170	8,332	1,119,654	787	1,109	7,936	1,070,775
RA9	805	1,138	8,130	1,117,852	764	1,075	7,860	1,068,445
RA10	804	1,138	8,140	1,120,216	763	1,074	7,867	1,070,065
RA11	805	1,135	8,186	1,109,142	763	1,071	7,909	1,058,370
RA12	808	1,143	8,152	1,104,925	767	1,080	7,880	1,055,091

ID	SO_2 1000 Tons	NO_X 1000 Tons	Hg Pounds	CO_2 1000 Tons	SO_2 1000 Tons	NO_X 1000 Tons	Hg Pounds	CO_2 1000 Tons
	$15 Adder (2008$)				$38 Adder (2008$)			
RA1	769	1,079	7,962	1,051,661	725	1,011	7,712	1,005,991
RA2	758	1,061	7,938	1,044,783	712	990	7,674	996,976
RA3	761	1,072	7,853	1,030,985	711	998	7,593	983,391
RA4	766	1,075	7,976	1,050,931	722	1,005	7,717	1,004,604
RA5	735	1,027	7,890	1,045,768	680	944	7,610	993,546
RA6	738	1,047	7,469	1,023,626	693	976	7,195	977,283
RA7	749	1,047	7,834	1,024,659	703	975	7,567	976,320
RA8	775	1,089	7,967	1,051,835	731	1,021	7,604	1,007,310
RA9	752	1,056	7,766	1,049,168	711	990	7,506	1,004,509
RA10	751	1,055	7,880	1,050,497	708	987	7,880	1,004,820
RA11	750	1,052	7,812	1,038,568	701	979	7,549	990,992
RA12	753	1,060	7,785	1,035,617	707	991	7,523	989,230

ID	SO_2 1000 Tons	NO_X 1000 Tons	Hg Pounds	CO_2 1000 Tons
	$61 Adder (2008$)			
RA1	705	975	7,598	983,131
RA2	690	952	7,546	972,473
RA3	688	961	7,475	959,728
RA4	701	968	7,593	980,942
RA5	655	901	7,472	966,702
RA6	673	942	7,056	954,462
RA7	681	938	7,438	951,671
RA8	711	987	7,604	985,331
RA9	692	958	7,387	983,189

ID	SO_2	NO_X	Hg	CO_2
	1000 Tons	1000 Tons	Pounds	1000 Tons
	$61 Adder (2008$)			
RA10	689	953	7,880	982,764
RA11	678	943	7,428	967,452
RA12	685	957	7,403	966,425

Supply Reliability

Energy Not Served

Figures 7.17 and 7.18 below show, respectively, the average annual amount of Energy Not Served (ENS) and the upper-tail mean Energy Not Served for the $8 CO_2 adder case, a measure of high-end supply reliability risk. It is clear that the system reliability is generally reduced under a 12% planning reserve margin. Asset-based portfolios tended to have higher reliability than portfolios that allowed short-term market purchases to meet firm requirements. RA6, which had no pulverized coal resources, also had a somewhat reduced level of reliability likely due to the combination of including front office transactions and a higher number of less reliable IGCC units in the portfolio. From a reliability basis, measured by energy not served, Portfolio RA5 has the highest reliability.

Figure 7.17 – Stochastic Average Annual Energy Not Served

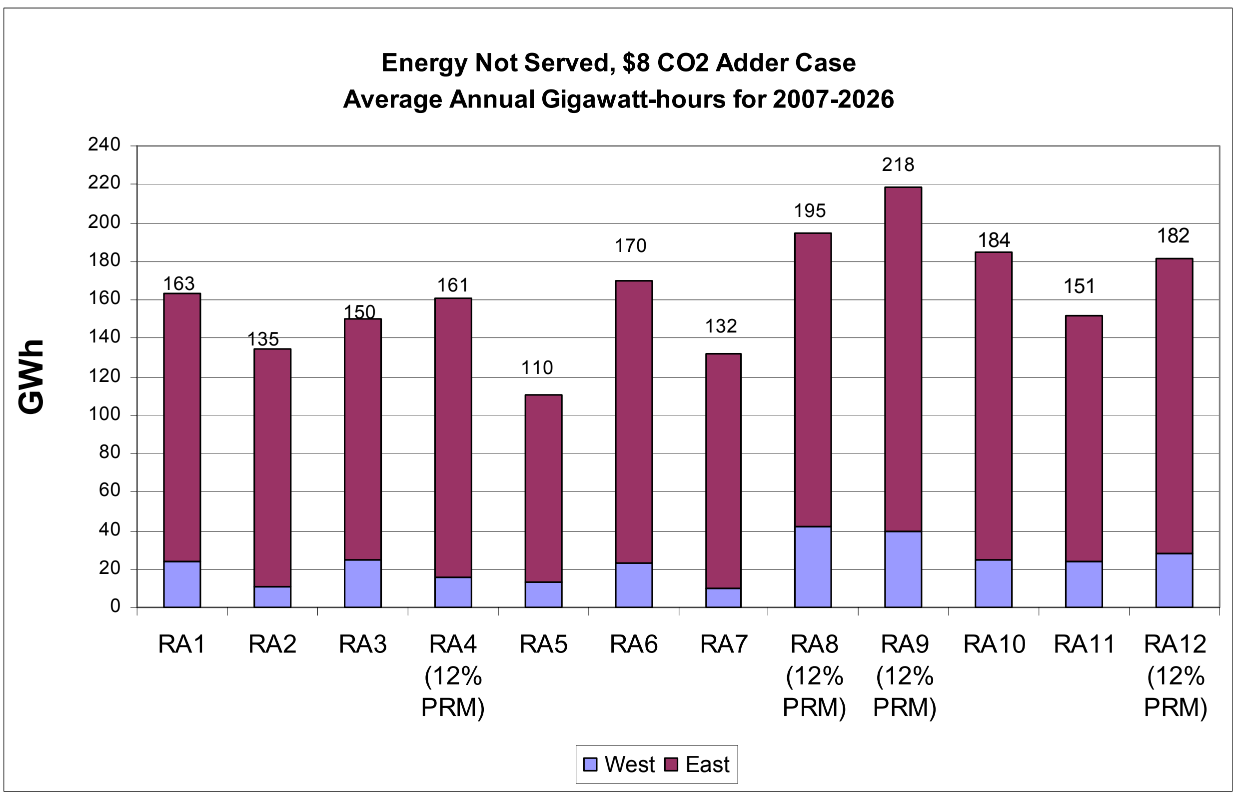
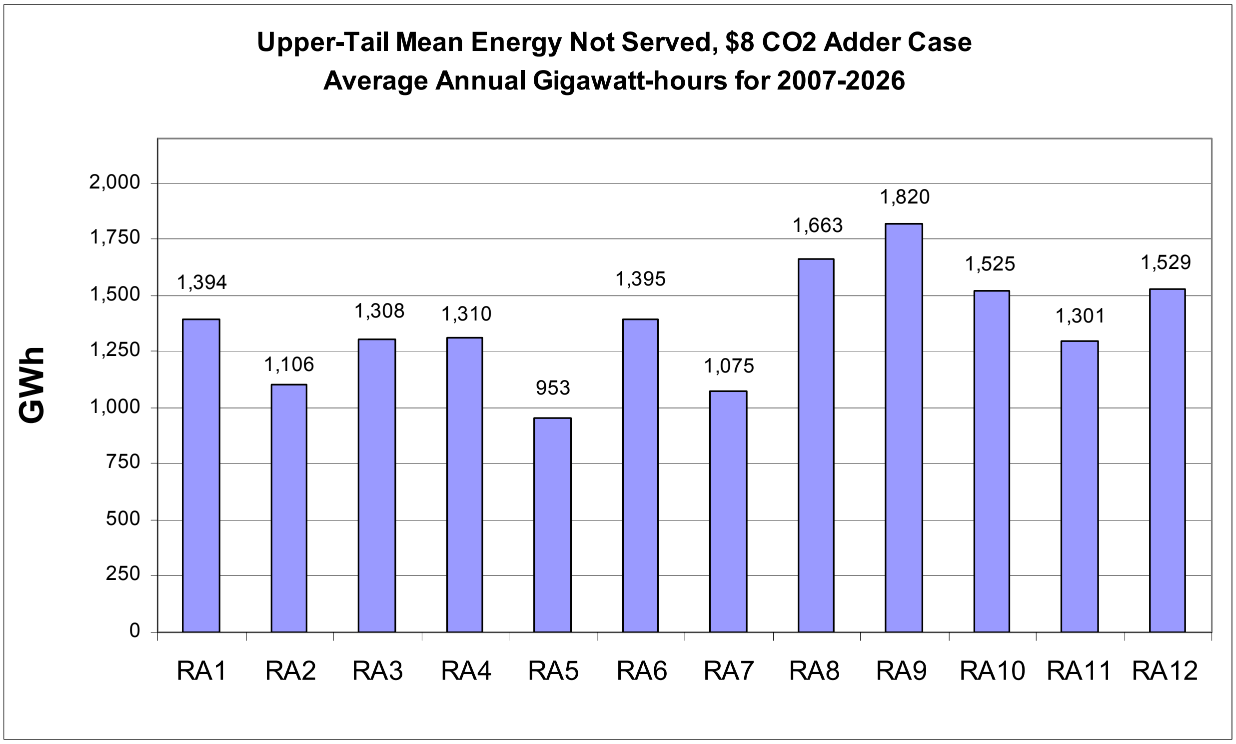


Figure 7.18 – Upper-Tail Stochastic Mean Energy Not Served



Loss of Load Probability

As discussed in Chapter 6, the Loss of Load Probability (LOLP) parameter is best represented by the probability of an occurrence of Energy Not Served (ENS). Table 7.27 displays the average Loss of Load Probability for each of the risk analysis portfolios modeled using the $8 CO_2 adder case. The first block of data is the average LOLP for the first ten years of the study period. The second block of data shows the same information calculated for the entire 20 years. The LOLP values in the second block are significantly higher than the first because the variability of the random draws for the stochastic variable draws increases over time, causing greater extremes in the out-years of the study period. The data is summarized against multiple levels of lost load, which shows the likelihood of losing various amounts of load in a single event.

Table 7.27 – Average Loss of Load Probability During Summer Peak

Average for operating years 2007 through 2016												
Event Size (MWh)	**RA1**	**RA2**	**RA3**	**RA4**	**RA5**	**RA6**	**RA7**	**RA8**	**RA9**	**RA10**	**RA11**	**RA12**
> 0	37%	34%	36%	35%	34%	37%	34%	37%	39%	37%	36%	38%
> 1,000	30%	26%	29%	27%	26%	30%	26%	30%	32%	30%	29%	31%
> 10,000	17%	13%	17%	14%	12%	17%	13%	17%	18%	17%	17%	18%
> 25,000	13%	10%	13%	11%	8%	13%	10%	13%	14%	13%	12%	14%
> 50,000	10%	7%	9%	7%	5%	10%	7%	10%	11%	10%	9%	10%
> 100,000	7%	5%	6%	5%	3%	7%	4%	7%	8%	7%	7%	8%
> 500,000	1%	0%	1%	0%	0%	1%	0%	1%	1%	1%	1%	1%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Average for operating years 2007 through 2026												
Event Size (MWh)	RA1	RA2	RA3	RA4	RA5	RA6	RA7	RA8	RA9	RA10	RA11	RA12
> 0	53%	52%	39%	54%	39%	52%	52%	54%	57%	55%	41%	43%
> 1,000	44%	44%	33%	45%	33%	44%	43%	46%	49%	47%	35%	37%
> 10,000	25%	24%	22%	26%	20%	26%	23%	27%	29%	27%	24%	26%
> 25,000	20%	18%	18%	20%	15%	20%	18%	21%	23%	22%	19%	21%
> 50,000	16%	14%	15%	15%	11%	16%	14%	17%	19%	18%	15%	17%
> 100,000	12%	10%	11%	11%	8%	12%	10%	13%	14%	12%	11%	13%
> 500,000	4%	3%	4%	4%	3%	4%	3%	4%	5%	4%	4%	4%
> 1,000,000	2%	2%	2%	2%	1%	2%	2%	2%	2%	2%	2%	2%

Table 7.28 displays the year-by-year results for the threshold value of 25,000 MWh. (As mentioned in Chapter 6, the 25,000 MWh case was selected as an example to show the annual LOLP as required in the Oregon Commission's 2004 IRP acknowledgement order.) For each year, the LOLP value represents the proportion of the 100 iterations where the July ENS was greater than 25,000 MWhs. This is the equivalent of 2,500 megawatts for 10 hours.

Table 7.28 – Year-by-Year Loss of Load Probability

(Probability of ENS Event > 25,000 MWh in July)

Year	RA1	RA2	RA3	RA4	RA5	RA6	RA7	RA8	RA9	RA10	RA11	RA12
2007	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
2008	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
2009	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
2010	13%	13%	13%	15%	13%	13%	13%	15%	15%	13%	13%	15%
2011	17%	17%	17%	17%	17%	17%	17%	17%	17%	17%	17%	17%
2012	9%	5%	9%	6%	5%	7%	5%	10%	12%	9%	9%	11%
2013	13%	6%	13%	7%	4%	13%	10%	15%	15%	14%	14%	17%
2014	14%	6%	17%	8%	3%	17%	6%	14%	15%	16%	15%	15%
2015	22%	14%	18%	16%	5%	23%	11%	19%	23%	24%	18%	22%
2016	19%	13%	16%	14%	6%	19%	13%	19%	21%	18%	16%	17%
2017	24%	23%	23%	22%	12%	29%	22%	23%	21%	21%	24%	25%
2018	22%	17%	19%	19%	17%	21%	17%	22%	22%	23%	19%	19%
2019	16%	19%	13%	19%	19%	13%	19%	15%	15%	15%	20%	21%
2020	23%	22%	18%	23%	21%	15%	22%	22%	23%	23%	22%	23%
2021	27%	23%	20%	26%	20%	23%	23%	26%	27%	27%	23%	25%
2022	35%	37%	33%	38%	31%	39%	37%	39%	40%	39%	36%	39%
2023	24%	23%	23%	28%	19%	27%	23%	30%	30%	31%	23%	24%
2024	40%	39%	31%	41%	26%	40%	39%	42%	43%	42%	30%	38%
2025	33%	30%	31%	45%	29%	35%	30%	46%	47%	43%	30%	33%
2026	31%	31%	31%	30%	28%	33%	31%	32%	48%	48%	28%	36%

Portfolio Resource Conclusions

Based on the stochastic simulation results, the best strategy for achieving a low-cost, risk-informed portfolio for PacifiCorp's customers is to include supercritical pulverized coal along with additional wind and natural gas to mitigate CO_2 cost risk. Although eliminating front office transactions after 2011 was found to be beneficial for reducing risk exposure, it also increased portfolio cost. On balance, PacifiCorp judges this resource type to be beneficial because it increases planning flexibility and resource diversity. Consequently, subsequent risk analysis portfolio development assumes that front office transactions will be available as a model option after 2011.

RISK ANALYSIS PORTFOLIO DEVELOPMENT – GROUP 2

As mentioned above, PacifiCorp developed the Group 2 risk analysis portfolios to account for current and expected resource policies in several of its state jurisdictions, and to address the new load forecast (See Chapter 4). Similar to the process used to derive the Group 1 portfolios, the CEM was allowed to optimize investment plans subject to certain resource constraints and strategies.

The CEM optimization process for the Group 2 portfolio was conducted in two phases. The first phase consisted of a screening test to determine general resource selection patterns under a variety of planning assumptions, including the new March 2007 load forecast. Model runs for this phase were based on medium-case scenario conditions, and subject to the following resource assumptions.

Coal Resources

- At least two supercritical pulverized coal resources were included in all of the new portfolios. This decision reflects the following findings from the previous portfolio evaluation work:
  - For Group 1 risk analysis portfolio development, the CEM chose the small Utah resource and the Wyoming resource for 2012–2014 in all portfolios for which the CEM was allowed to optimize their selection and timing.
  - The stochastic simulations indicated that removing or deferring these coal resources raised both portfolio cost and risk, even under the higher CO_2 adder cases.

- The Wyoming supercritical pulverized coal resources were resized from 750 megawatts each to 527 megawatts. This size change is intended to mitigate the customer rate and carbon footprint impacts of new coal resources. Also, the large Utah SCPC resource was changed from 600 to 575 megawatts. These changes are consistent with the resource sizes assumed for PacifiCorp's 10-year Business Plan.[59]

- The second Utah and Wyoming supercritical pulverized coal units were removed as resource options for all portfolios.

[59] Other resource assumption changes made to conform to the PacifiCorp Business Plan included (1) removing the 100 MW Desert Power QF from the load and resource balance due to the project's owner declaring bankruptcy, and (2) excluding the Blundell expansion project. (PacifiCorp's economic evaluation of the Blundell project found it to not be cost-effective. This report was filed in all six states in March 2007 to comply with a PacifiCorp-MEHC acquisition commitment.)

- The west IGCC resources were removed as options for all portfolios. These IGCC units were patterned after the planned Pacific Mountain Energy Center IGCC project in Kalama, Washington. Reasons for exclusion included (1) regulatory uncertainties regarding siting of coal-based generation in Washington, (2) commercial uncertainties regarding capital costs, and (3) the unique project-specific characteristics (such as a proposed fuel supply that includes imported petroleum coke) that make it unsuitable as a generic IGCC resource.

Wind Resources

- PacifiCorp developed and applied a new fixed wind investment schedule for all Group 2 portfolios except for RA13, consisting of a total of 1,600 megawatts of wind resources beyond the 400 megawatts already reflected in the load and resource balance. This schedule is based on acquiring the 1,400 megawatts of wind by 2010 (reflecting an accelerated time table relative to the initial investment schedule developed for risk analysis portfolios) and the additional 600 megawatts tested as a resource strategy in the Group 1 analysis. Table 7.29 shows this new wind investment schedule for the 1,600 megawatts of wind, including the associated cumulative capacity contributions.[60]

Table 7.29 – Wind Resource Additions Schedule for Risk Analysis Portfolios

Year	Annual Additions, Nameplate Capacity (MW)	Location	Cumulative Wind Nameplate Capacity (MW)	Cumulative Wind Peak Capacity Contribution (MW)
2007	300	Southeast Washington	300	14
2008	300	Wyoming; Southeast Washington	600	38
2009	100	North Central Oregon	700	75
2010	300	Wyoming; North Central Oregon	1,000	119
2011	200	Wyoming	1,200	127
2012	100	North Central Oregon	1,300	146
2013	300	Wyoming	1,600	207

- The capacity factor for southeast Wyoming wind resources was increased from 32% to 40% to reflect updated operational expectations for these wind sites.

Gas Resources

- For initial CEM resource screening analysis, there were no restrictions placed on the type and timing of gas resources.

Front Office Transactions

- The model is able to select front office transactions after 2011.

Transmission Resources

- PacifiCorp incorporated the following set of transmission resources in all the Group 2 portfolios:

[60] The capacity contribution of this new investment schedule is smaller than the contribution for the previous schedule, even though there is more nameplate capacity added. This is due to the relocation of wind projects to areas for which incremental additions have less peak-hour load carrying capability.

- Path C Upgrade: Borah to Path-C South to Utah North
- Utah - Desert Southwest (Includes Mona - Oquirrh)[61]
- Mona - Utah North
- Craig-Hayden to Park City
- Miners - Jim Bridger - Terminal
- Jim Bridger - Terminal
- Walla Walla - Yakima
- West Main - Walla Walla

These resources are supported by previous portfolio analysis, and are consistent with both the PacifiCorp 10-year Business Plan and MEHC transmission commitments. Additionally, as mentioned in Chapter 2, these transmission resources represent proxies for future transmission requirements rather than specific projects.

Planning Reserve Margin

- Test portfolios with both a 12% and 15% planning reserve margin.

The second CEM portfolio optimization phase consisted of the development of the risk analysis portfolios to be simulated with the PaR module. The results of the CEM screening runs were used to inform the selection and timing of resources. Based on the resulting fixed generation resource investment schedule for each portfolio, a CEM run determined the front office transactions needed to meet the planning reserve margin. (See Figure 6.4 in Chapter 6 for a generic description of this two-stage CEM optimization process.)

Alternative Resource Strategies

Having already determined a new wind investment schedule and the coal resources to include in the Group 2 portfolios, PacifiCorp considered a relatively small set of alternative resource strategies to be evaluated. These strategies focus on the timing of the two supercritical coal resources and the mix of gas resources. Specifically, the strategies test (1) whether the new resource assumptions alter the CEM's optimal timing for the two supercritical coal plants, (2) reliance on only combined cycle combustion turbines versus a combination of CCCTs and non-base-load gas resources to meet the latest load growth projections, (3) the timing and type of resources needed to make up for the loss of the BPA peaking contract in August 2011 (i.e., determine the resource selection impact of removing the contract in 2011 rather than 2012 to ensure that new resources are selected to meet load by August 2011), and (4) alternative planning reserve margins—12% and 15%. For the pulverized coal resources, the CEM was allowed to select the small Utah unit for 2012 or 2013 only, while the Wyoming resource could be acquired in any year after 2013.

The major conclusions obtained from the associated CEM screening runs include the following.

- **Coal resource timing –** The Utah small supercritical coal resource was always selected in 2012, while the Wyoming supercritical coal resource (527 megawatts) was always selected in 2014.
- **Gas resource mix –** When the CEM was allowed to optimize the selection and timing of gas resources, it chose a combination of CCCTs and SCCT frames; the west CCCT was always

[61] This resource was included in the 10-year PacifiCorp Business Plan.

selected in 2012. Restricting the model to choose only CCCTs resulted in just one east CCCT selected in 2012. (This is in addition to the west CCCT selected in 2012.)

- **Timing of resource acquisition to address expiration of the BPA peak contract –** Removing the BPA contract in 2011 (as opposed to 2012) had no effect on the timing of the west CCCT assuming unlimited availability of front office transactions in 2011.
- **Alternative planning reserve margins –** Under a 12% planning reserve margin, allowing the model to choose its own gas resources resulted in two SCCT frames selected in 2012 – one in the east and one in the west; this is in addition to the west CCCT selected in 2012. Under a 15% planning reserve margin with no gas resource option restrictions, the CEM portfolio solution included about 200 megawatts of additional gas resources by 2016; east SCCT frames were selected in 2010 and 2012 in addition to an east CCCT in 2012.

Based on these results, PacifiCorp developed five portfolios for stochastic simulation. These portfolios are intended to compare CCCTs against reliance on the market to meet new forecasted loads under alternative planning reserve margin targets (12% and 15%). Combined cycle plants were chosen as the proxy gas-fired resource type for two reasons. First, the PaR stochastic simulation captures extrinsic (or optionality) value of a resource, while the CEM does not. A CCCT is expected to have a lower PVRR impact than a non-base-load gas resource with all else held constant. Second, the larger CCCT minimizes the number of gas resources added in a single year.

In addition, all five risk analysis portfolios have a west CCCT added in 2011 to ensure that a resource is available to meet west-side load by August 2011. Finally, the amount of annual front office transactions needed to balance the system is determined by CEM; no caps are placed on the resources.

Table 7.30 outlines the specifications for the five risk analysis portfolios (labeled RA13 through RA17), and presents the design rationale and common features for each.

Table 7.30 – Risk Analysis Portfolio Descriptions (Group 2)

ID	Description	Design Rationale	Features
RA13	An updated "Base Case" resource proposal that mirrors the original PacifiCorp Business Plan's base load resources. This portfolio, based on a 12% planning reserve margin, includes four supercritical pulverized coal resources: the small Utah SCPC (2012), the Wyoming SCPC (2014), the large Utah SCPC (2017), and the second Wyoming SCPC (2018).	This portfolio serves as the reference portfolio for comparison with the other risk analysis portfolios. It reflects a coal- and market- intensive resource strategy.	• Based on the revised load forecast (March 2007) • Wind investment schedule assumed for original Business Plan • All portfolios use the same transmission investment schedule

ID	Description	Design Rationale	Features
RA14	This portfolio addresses the higher east load forecast by adding two east CCCTs: one in 2012 (2x1 F type) and one in 2016 (1x1 G type).	Tests the strategy of meeting east load growth with CCCTs as opposed to the market.	• Based on the revised load forecast (March 2007) • Small Utah SCPC plant acquired in 2012 • Wyoming SCPC acquired in 2014 • West CCCT acquired in 2011 • Revised wind investment schedule (1,400 MW by 2010; 600 MW by 2013 – Total of 2,000 MW by 2013) • All portfolios use the same transmission investment schedule • 12% Planning reserve margin except RA16
RA15	This portfolio addresses the revised east load forecast by adding just one east CCCT in 2012. A 12% planning reserve margin is met with front office transactions.	Tests the strategy of meeting east load growth with a mix of CCCT capacity and the market.	
RA16	RA14 based on a 15% planning reserve margin; the higher reserve margin is met with CCCT capacity and front office transactions	Tests the consequences of meeting the higher planning reserve margin with market resources.	
RA17	This portfolio addresses the revised load forecast by relying on front office transactions only.	Tests the strategy of using market purchases to meet the increased forecasted load.	

Tables 7.31 through 7.35 present the detailed supply- and demand-side investment schedules for each portfolio. Table 7.36 provides the common transmission investment schedule for all the Group 2 portfolios.

Table 7.31 – Resource Investment Schedule for Portfolio RA13

			Nameplate Capacity, MW											
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
EAST	Utah pulverized coal	Supercritical						340						
	Wyoming pulverized coal	Supercritical								527				
	Utah pulverized coal	Supercritical											575	
	Wyoming pulverized coal	Supercritical												527
	Combined cycle CT	2x1 F class with duct firing												
	Combined cycle CT	1x1 G class with duct firing												
	Combined Heat and Power	Generic east-wide						25						
	Renewable	Wind, Wyoming and Idaho	100	200		100	200	100	100					
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18					
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	451	550	281	281	911	1,054	,209	1,121	811
WEST	Combined cycle CT	2x1 F Type with duct firing												
	Combined Heat and Power	Generic west-wide						75						
	Renewable	Wind, SE Washington												
	Renewable	Wind, NC Oregon	200											
	Class 1 DSM*	Sch. irrigation				12	11	12						
	Front office transactions**	Flat annual product	-	-	-	134	222	1,300	1,350	513	413	551	663	840
	Annual Additions, Long Term Resources		**300**	**200**	**-**	**112**	**237**	**577**	**118**	**527**	**-**	**-**	**575**	**527**
	Annual Additions, Short Term Resources		**-**	**-**	**-**	**585**	**772**	**1,581**	**1,631**	**1,424**	**1,467**	**1,760**	**1,784**	**1,651**
	Total Annual Additions		**300**	**200**	**0**	**697**	**1,009**	**2,158**	**1,749**	**1,951**	**1,467**	**1,760**	**2,359**	**2,178**

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

Table 7.32 – Resource Investment Schedule for Portfolio RA14

	Resource	Type	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
			Nameplate Capacity, MW									
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combined cycle CT	2x1 F class with duct firing						548				
	Combined cycle CT	1x1 G class with duct firing										357
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	393	272	97	3	149	192	165
West	CCCT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Load control, Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	-	219	64	555	657	247	246	249
	Annual Additions, Long Term Resources		**300**	**300**	**100**	**312**	**839**	**1,125**	**318**	**527**	**-**	**357**
	Annual Additions, Short Term Resources		**-**	**-**	**-**	**612**	**336**	**652**	**660**	**396**	**438**	**414**
	Total Annual Additions		**300**	**300**	**100**	**924**	**1,175**	**1,777**	**978**	**923**	**438**	**771**

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

Table 7.33 – Resource Investment Schedule for Portfolio RA15

	Resource	Type	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
			Nameplate Capacity, MW									
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combined cycle CT	2x1 F class with duct firing						548				
	Combined cycle CT	1x1 G class with duct firing										
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	393	272	97	3	149	192	349
West	Combined cycle CT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Load control, Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	-	219	64	555	657	247	246	384
	Annual Additions, Long Term Resources		**300**	**300**	**100**	**312**	**839**	**1,125**	**318**	**527**	**-**	**-**
	Annual Additions, Short Term Resources		**-**	**-**	**-**	**612**	**336**	**652**	**660**	**396**	**438**	**733**
	Total Annual Additions		**300**	**300**	**100**	**924**	**1,175**	**1,777**	**978**	**923**	**438**	**733**

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

Table 7.34 – Resource Investment Schedule for Portfolio RA16

			Nameplate Capacity, MW									
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combined cycle CT	2x1 F class with duct firing					548					
	Combined cycle CT	2x1 F class with duct firing						548				
	Combined cycle CT	1x1 G class with duct firing										
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	108	111	553	103	73	-	-	-	272
West	Combined cycle CT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Load control, Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	-	289	-	366	533	261	260	263
		Annual Additions, Long Term Resources	300	300	100	312	1,387	1,125	318	527	-	-
		Annual Additions, Short Term Resources	-	108	111	842	103	439	533	261	260	535
		Total Annual Additions	300	408	211	1,154	1,490	1,564	851	788	260	535

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

Table 7.35 – Resource Investment Schedule for Portfolio RA17

			Nameplate Capacity, MW									
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combined cycle CT	2x1 F class with duct firing										
	Combined cycle CT	1x1 G class with duct firing										
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	393	272	281	255	394	616	706
West	Combined cycle CT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Load control, Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	-	219	64	861	894	492	312	517
		Annual Additions, Long Term Resources	**300**	**300**	**100**	**312**	**839**	**577**	**318**	**527**	**-**	**-**
		Annual Additions, Short Term Resources	**-**	**-**	**-**	**612**	**336**	**1,142**	**1,149**	**886**	**928**	**1,223**
		Total Annual Additions	**300**	**300**	**100**	**924**	**1,175**	**1,719**	**1,467**	**1,413**	**928**	**1,223**

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

Table 7.36 – Transmission Resource Investment Schedule for All Group 2 Portfolios

		Transfer Capability, Megawatts									
	Resource	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Path C Upgrade: Borah to Path-C South to Utah North				300						
	Utah - Desert Southwest (Includes Mona - Oquirrh)						600				
	Mona - Utah North						400				
	Craig-Hayden to Park City						176				
	Miners - Jim Bridger - Terminal						600				
	Jim Bridger - Terminal								500		
West	Walla Walla - Yakima				400						
	West Main - Walla Walla					630					
	Total Annual Additions	-	-	-	700	630	1,776	-	500	-	-

STOCHASTIC SIMULATION RESULTS

The five Group 2 risk analysis portfolios were run in stochastic simulation mode to determine cost, risk, reliability, and emission performance results. The tables and charts below show how the portfolios compare to one another on the basis of these results.

Stochastic Mean Cost

Table 7.37 compares the stochastic mean PVRR for each portfolio across the CO_2 adder cases, as well as by CO_2 compliance strategy (per-ton CO_2 tax and cap-and-trade). Portfolio RA14 (two east CCCTs) has the lowest stochastic cost at each adder level. RA17 (no east CCCTs) has the highest cost under the \$0, \$8, \$15, and \$38 adder levels, while RA13 has the highest cost under the \$61 adder. The average cost deviation among the portfolios is about \$200 million for the \$0 adder case, and increases to over \$600 million at the \$61 adder level.

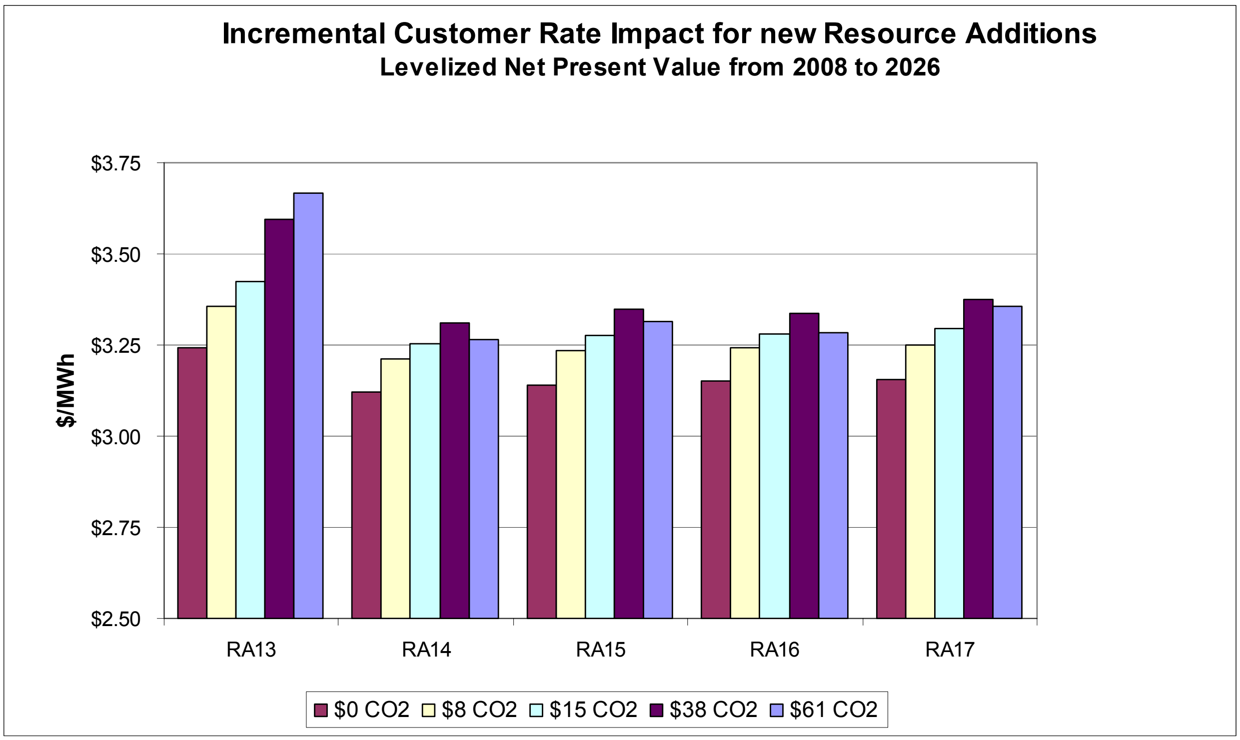
Table 7.37 – Stochastic Mean PVRR by CO_2 Adder Case

	Tax Strategy (Million $)						
ID	**$0 Adder (2008$)**	**$8 Adder (2008$)**	**$15 Adder (2008$)**	**$38 Adder (2008$)**	**$61 Adder (2008$)**	**Average**	**Rank**
RA13	22,917	26,930	29,002	36,161	43,368	31,676	5
RA14	22,570	26,478	28,401	35,008	41,634	30,818	1
RA15	22,631	26,551	28,482	35,139	41,820	30,925	3
RA16	22,645	26,544	28,454	35,021	41,854	30,850	2
RA17	22,737	26,669	28,616	35,351	42,137	31,102	4
	Cap & Trade (Million $)						
ID	**$0 Adder (2008$)**	**$8 Adder (2008$)**	**$15 Adder (2008$)**	**$38 Adder (2008$)**	**$61 Adder (2008$)**	**Average**	**Rank**
RA13	21,606	22,010	22,282	22,673	22,716	22,257	5
RA14	21,260	21,559	21,682	21,521	20,983	21,401	1
RA15	21,322	21,632	21,763	21,652	21,168	21,507	3
RA16	21,336	21,625	21,736	21,534	20,933	21,433	2
RA17	21,427	21,750	21,897	21,864	21,486	21,685	4

Customer Rate Impact

The portfolio customer rate impact results for each CO_2 cost adder level are reported in Figure 7.19, and are based on a CO_2 cap-and-trade compliance strategy. Portfolio RA14 has the smallest impact across all the CO_2 adder levels. The difference between the lowest and highest impact (RA13) under the $0 adder case is $0.12/MWh, and increases to $0.40/MWh for the $61 adder case.

Figure 7.19 – Customer Rate Impact



Emissions Externality Cost

For the Group 2 portfolios, PacifiCorp estimated the emissions externality cost given two regulatory strategies: cap-and-trade and a per-ton tax. For the tax strategy, each ton of emissions (pounds in the case of mercury) is assessed an emissions tax equivalent to the cost adder value. Table 7.38 shows the externality cost for each portfolio by CO_2 adder level and regulation type. Note that the portfolio rankings, based on the average externality cost across the CO_2 adder cases, did not change from one regulatory strategy to other.

Portfolio RA16 had the lowest externality cost, followed closely by RA14. In contrast, RA13 had the highest externality cost due to the two additional coal plants not included in the other portfolios. Nevertheless, the externality cost for RA13 under the tax basis is only six percent higher than that for the best-performing portfolio, RA16. Of note is that under the cap-and-trade scheme, RA14 and RA16 have a negative externality cost under the $61 adder. This result is a consequence of large positive annual allowance balances that have accrued for part of the study period as a result of the cap-and-trade modeling assumptions. Future modeling work is expected to focus on alternative specifications for CO_2 compliance strategies.

Table 7.38 – Portfolio Emissions Externality Cost by CO_2 Adder Level and Regulation Type

ID	Incremental Stochastic Mean PVRR by CO_2 Adder (Tax Strategy), Million $						
	CO_2 Adder Level (2008$)					Average	Rank
	$0	$8	$15	$38	$61		
RA13	-	4,013	6,085	13,244	20,451	10,948	5
RA14	-	3,908	5,831	12,438	19,064	10,310	2
RA15	-	3,920	5,850	12,507	19,188	10,366	3
RA16	-	3,898	5,809	12,376	18,939	10,255	1
RA17	-	3,933	5,879	12,614	19,400	10,457	4

ID	Incremental Stochastic Mean PVRR by CO_2 Adder (Cap and Trade Strategy), Million $						
	CO_2 Adder Level (2008$)					Average	Rank
	$0	$8	$15	$38	$61		
RA13	-	404	676	1,067	1,110	814	5
RA14	-	298	421	261	(278)	176	2
RA15	-	310	441	330	(154)	232	3
RA16	-	289	399	198	(403)	121	1
RA17	-	323	470	437	59	322	4

Capital Cost

Figure 7.20 shows the total capital cost for each portfolio, expressed on a net present value of the sum of all capital costs accrued for 2007–2026. Portfolios RA14 and RA16 have the highest capital cost on account of the three CCCT resources acquired in the 2012-2016 timeframe. RA13 has the lowest capital cost—despite four coal plants—because of the lack of the east CCCT in 2011 and the accelerated wind investment schedule, as well as the cost discount impact of two coal resources acquired beyond 2016.

Portfolio Construction Cost Risk

PacifiCorp calculated a measure of portfolio construction cost risk using its "high case" per-kilowatt capital cost values. (These values are reported in Chapter 5, Tables 5.1 and 5.2.) The high capital cost ($/kW) estimates are comprised of a standard project construction cost contingency (10%), as well as technology-specific contingencies and "optimism" factors for first-of-a-kind technologies that account for the established tendency to underestimate actual costs (applicable to IGCC). The source for the technology cost contingency and optimism factors is the U.S. Energy Information Administration (*Assumptions to the Annual Energy Outlook 2006,* DOE/EIA-0554(2006), March 2006).

The risk value for each portfolio is the difference between the PVRR calculated with the high per-kW capital cost and the PVRR calculated with the average per-kW capital cost. The table shows the results for the 17 risk analysis portfolios. Portfolio RA9 had the lowest construction cost risk, while RA5 had the highest. Although RA9 includes the more expensive IGCC plants (on a per-kW basis), the smaller capacity sizes of these units, combined with deferral and removal of the supercritical pulverized coal plants, results in a lower overall capital cost.

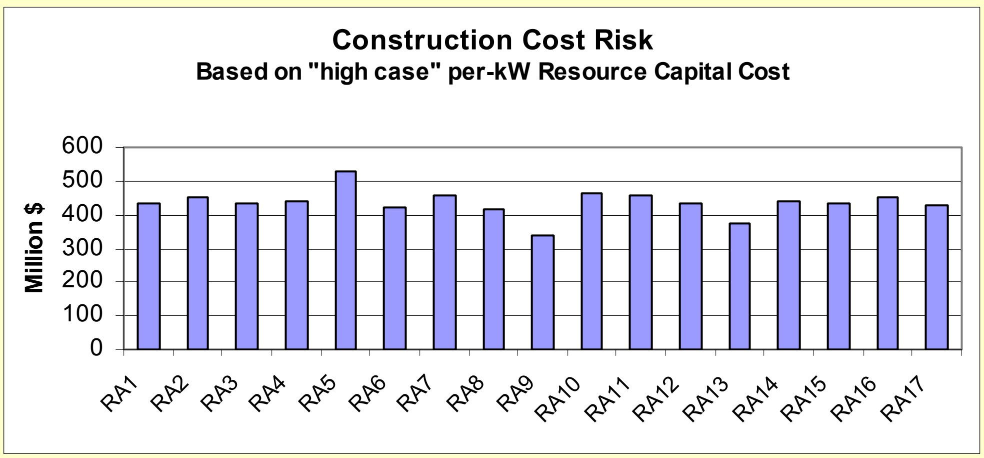
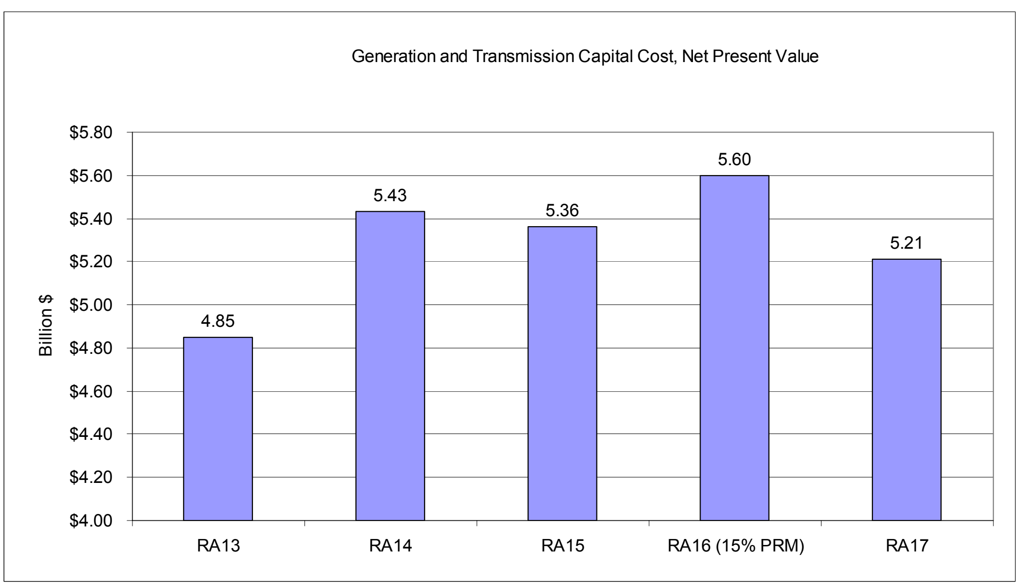


Figure 7.20 – Total Capital Cost by Portfolio



Stochastic Risk Measures

Table 7.39 reports the portfolio stochastic risk results for each of the CO_2 adder cases. Risk exposure, production cost standard deviation, fifth-percentile PVRR, ninety-fifth-percentile PVRR, and upper-tail PVRR are presented for the cap-and-trade compliance strategy. (Note that relative risk measure rankings are the same under both CO_2 emissions compliance strategies.)

Portfolio RA13, with four pulverized coal plants, performed the best overall on the risk measures, followed by RA16 with its two east CCCT resources and 15% planning reserve margin. As expected, RA17 has the highest risk due to its heavy reliance on the market. Interestingly, RA14 performed the best on the basis of the 5th percentile measure, indicating that it could be a good performer under a confluence of low-cost conditions.

Table 7.39 – Stochastic Risk Results

ID	Risk Exposure (Upper-Tail PVRR minus Mean PVRR)		Standard Deviation	5th Percentile	95th Percentile	Upper-Tail Mean
	Million $	Rank				
$0 Adder (2008$)						
RA13	43,703	2	12,020	13,628	36,692	65,309
RA14	44,056	3	12,094	13,584	35,315	65,316
RA15	44,718	4	12,296	13,518	35,918	66,040
RA16	43,638	1	11,987	13,732	35,196	64,974
RA17	45,339	5	12,460	13,464	36,198	66,766
$8 Adder (2008$)						
RA13	46,984	1	13,016	11,846	38,652	68,994
RA14	47,523	3	13,134	11,620	37,066	69,082
RA15	48,198	4	13,339	11,576	37,665	69,830
RA16	47,128	2	13,034	11,693	36,970	68,753
RA17	48,812	5	13,501	11,661	37,935	70,562
$15 Adder (2008$)						
RA13	48,668	1	13,556	10,987	39,736	70,950
RA14	49,195	3	13,666	10,725	38,038	70,977
RA15	49,863	4	13,868	10,695	38,629	71,626
RA16	48,775	2	13,560	10,840	37,933	70,510
RA17	50,501	5	14,036	11,903	38,907	72,398
$38 Adder (2008$)						
RA13	55,855	2	15,852	9,908	43,993	43,993
RA14	56,258	3	15,927	8,226	41,426	41,426
RA15	56,971	4	16,136	8,223	42,019	42,019
RA16	55,835	1	15,827	8,264	41,311	41,311
RA17	57,704	5	16,322	8,357	42,326	42,326
$61 Adder (2008$)						
RA13	64,344	2	18,544	6,740	48,252	87,060
RA14	64,614	3	18,584	4,562	44,875	85,596
RA15	65,396	4	18,805	4,728	45,468	86,564
RA16	64,159	1	18,482	4,481	44,719	85,093

ID	Risk Exposure (Upper-Tail PVRR minus Mean PVRR)		Standard Deviation	5th Percentile	95th Percentile	Upper-Tail Mean
	Million $	Rank				
RA17	66,238	5	19,010	5,611	45,870	87,724
Average across Adder Cases						
RA13	51,911	2	14,598	10,622	41,465	74,168
RA14	52,329	3	14,681	9,743	39,344	73,730
RA15	53,029	4	14,889	9,748	39,940	74,537
RA16	51,907	1	14,578	9,802	39,226	73,340
RA17	53,719	5	15,066	9,999	40,247	75,403

Cost/Risk Tradeoff Analysis

The three figures below are scatter plots of portfolio cost (PVRR) and risk exposure. Figure 7.21 plots the average PVRR and risk exposure across the CO_2 adder cases. Figures 7.22 and 7.23 show the cost-risk relationship for the $0 CO_2 adder case and the $61 CO_2 adder case, respectively.

The figures indicate that RA14 has the best balance of cost and risk on an average basis across the five CO_2 adder cases, as well as for adders greater than $0. Portfolio RA17 fares relatively poorly, having both a higher cost and risk than the other portfolios.

Figure 7.21 – Average Stochastic Cost versus Risk Exposure

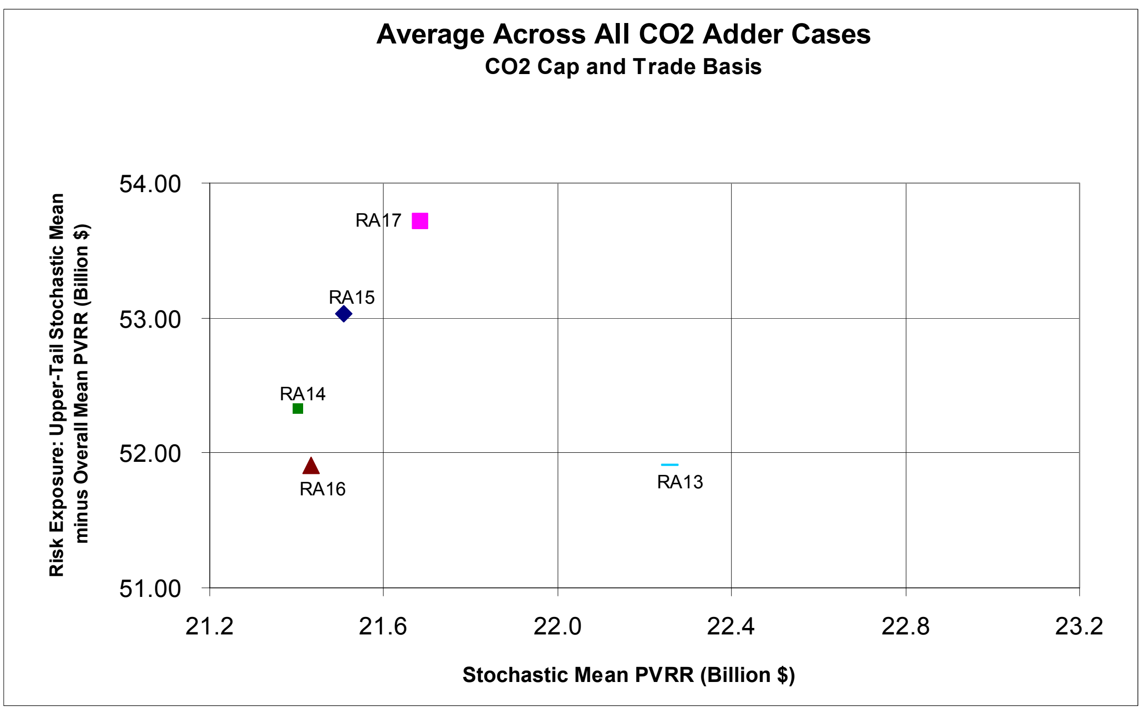


Figure 7.22 – Stochastic Cost versus Risk Exposure for the $0 CO_2 Adder Case

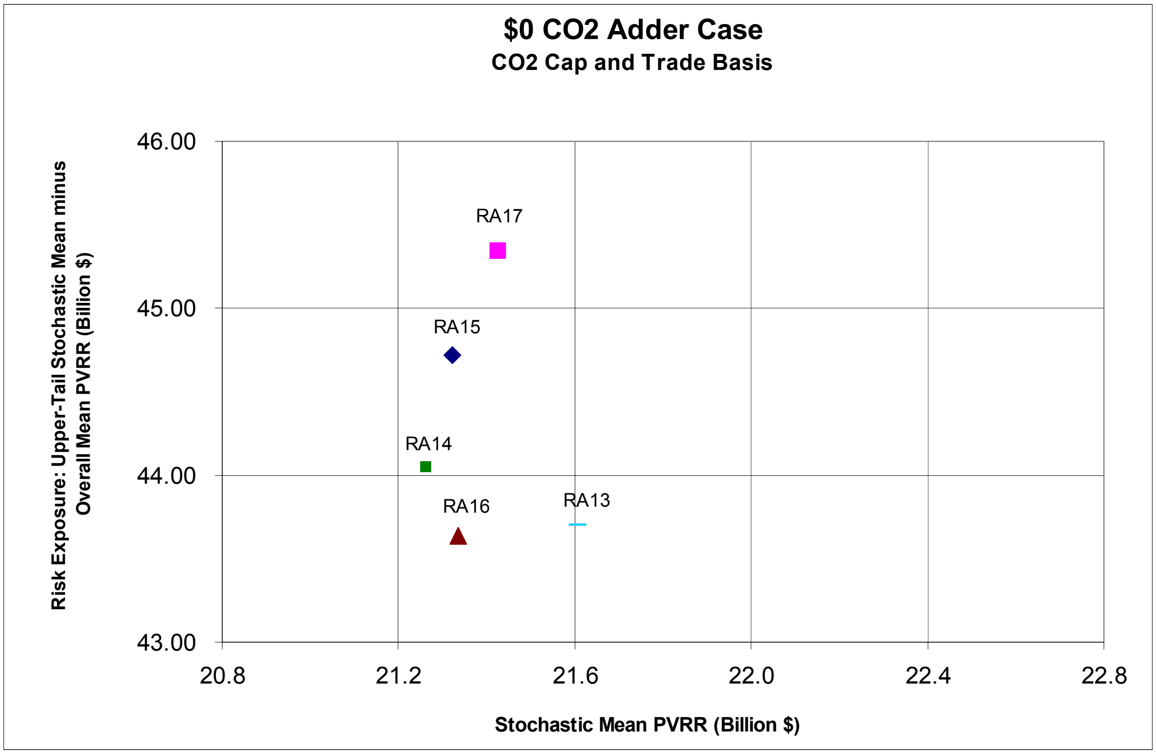
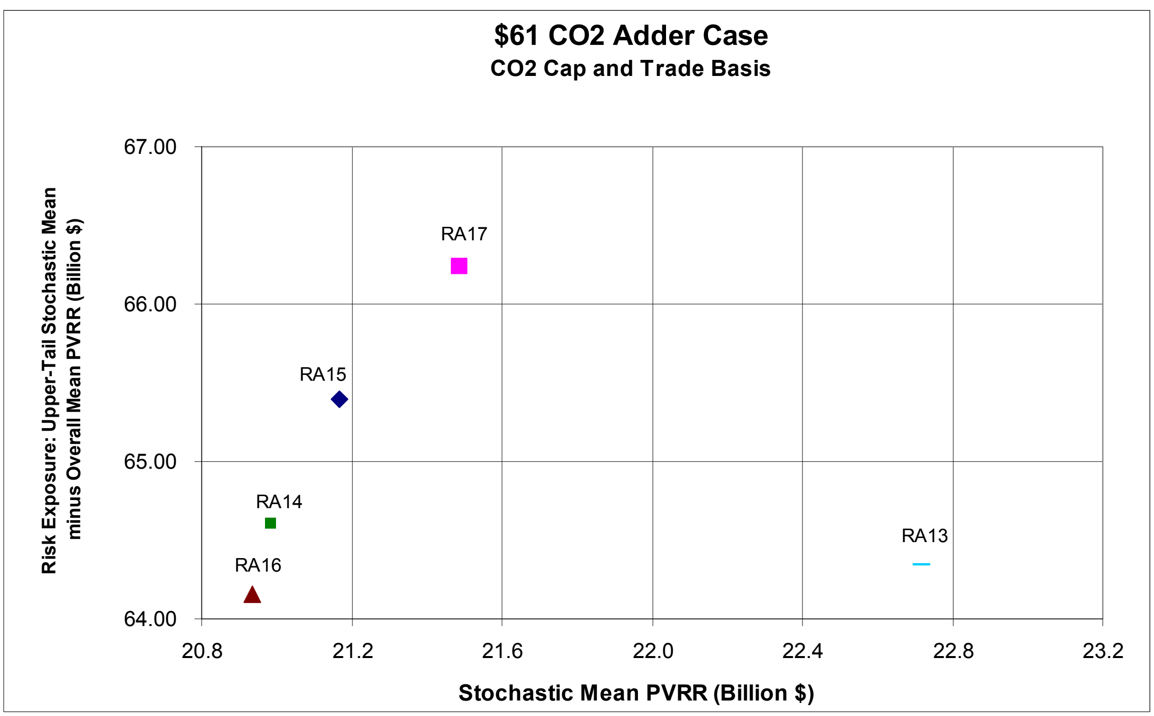


Figure 7.23 – Stochastic Cost versus Risk Exposure for the $61 CO_2 Adder Case



Carbon Dioxide and Other Emissions

Table 7.40 reports for the portfolios the total system CO_2 emissions for the \$8 adder and \$61 adder cases. Total emissions are presented as the contribution from direct sources (generators) plus indirect emissions from purchases less emissions attributed to wholesale sales[62], and are reported for 2007-to-2016 and 2007-to-2026. Portfolio RA16 has the lowest CO_2 emissions for both CO_2 adder levels, followed closely by RA14. For RA16, the early addition of a CCCT displaces front office transactions, which have a slightly higher CO_2 emission rate than a CCCT. Portfolio RA13 has the highest CO_2 emissions because of the additional two coal plants.

CO_2 Adder Breakeven Analysis for Coal versus Gas Combined Cycle

PacifiCorp conducted a study to determine the CO_2 adder level that causes the CEM to select a combined cycle combustion turbine over a supercritical pulverized coal plant. The model was executed at various CO_2 adders between \$8/ton and \$40/ton (in 2008 dollars) to converge on the breakeven point. The study was performed on a portfolio that had the 600 megawatts of extra wind and a Wyoming supercritical pulverized coal acquired in 2016. The simulations were designed to hold all influences constant except for the substitution of one coal plant with a CCCT. Study assumptions included the following:

- The pulverized coal and CCCT test resources were both sized at 575 megawatts
- The two resources were located in the same topology bubble (Utah South)
- The CEM was required to select either the coal or CCCT resource in 2016, but not both (mutually exclusive options)
- Each simulation used a set of forward natural gas and wholesale electricity prices that were adjusted to account for the effect of the CO_2 adder level tested

The breakeven CO_2 adder level was found to be \$38/ton; up to this level, the CEM selected the coal plant rather than the CCCT. Over the range of CO_2 adders tested, a \$1/ton increase in the adder translated into an average \$373 million increase in deterministic Present Value of Revenue Requirements. (Note that the CEM treats the cost adder as an emissions tax.)

Table 7.40 – CO_2 Emissions by Adder Case and Time Period (1,000 Tons)

	$8 CO_2 Adder Case					
	2007 to 2016			2007 to 2026		
Scenario ID	Direct (Generation only)	Total Direct and Net Indirect	Rank (Total Direct and Net Indirect)	Direct (Generation only)	Total Direct and Net Indirect	Rank (Total Direct and Net Indirect)
RA13	493,664	523,812	5	1,064,261	1,127,571	5
RA14	495,099	507,807	2	1,019,946	1,064,710	2
RA15	495,040	508,332	3	1,021,983	1,068,540	3
RA16	493,225	503,148	1	1,017,187	1,057,885	1
RA17	495,186	512,737	4	1,023,767	1,075,848	4

[62] Emissions imputed to purchases are based on a survey of 2005 PacifiCorp historical purchases, at 0.565 tons CO_2/MWh. Emissions imputed to sales are based on a year-by-year system weighted average rate: Thermal plus Purchases CO2 (tons)/Total System Generation (MWh).

	$61 CO_2 Adder Case					
	2007 to 2016			2007 to 2026		
Scenario ID	Direct (Generation only)	Total Direct and Net Indirect	Rank (Total Direct and Net Indirect)	Direct (Generation only)	Total Direct and Indirect	Rank (Total Direct and Net Indirect)
RA13	478,176	515,380	5	972,566	1,085,311	5
RA14	476,743	496,788	2	922,926	1,016,625	2
RA15	477,038	497,663	3	926,375	1,022,002	3
RA16	474,074	491,563	1	918,006	1,008,456	1
RA17	478,560	503,290	4	931,329	1,031,967	4

Figures 7.24 and 7.25 show the annual CO_2 emissions trend from 2007 through 2026 for the $8 and $61 CO_2 adder cases, respectively. The impact of the wind and CCCT additions is evident from the emissions drop from 2011 through 2012 for portfolios RA14, RA15, and RA16. The increasing annual emissions after this point are attributable to the addition of the Wyoming supercritical pulverized coal resource in 2014 and an increase in front office transactions. The significant emissions drop in 2019 for all the portfolios is caused by the addition of CCCT-based growth stations, which replace the acquisition of front office transactions.

For the $61 adder case, the large CO_2 emission decreases in 2013 through 2015 are due to the phasing in of the adder, which starts in 2010 but ramps up significantly in 2014 and 2015.

Figure 7.24 – Annual CO_2 Emission Trends, 2007-2026, ($8 CO_2 Adder Case)
(Generation plus the net indirect effect of wholesale purchases and sales)

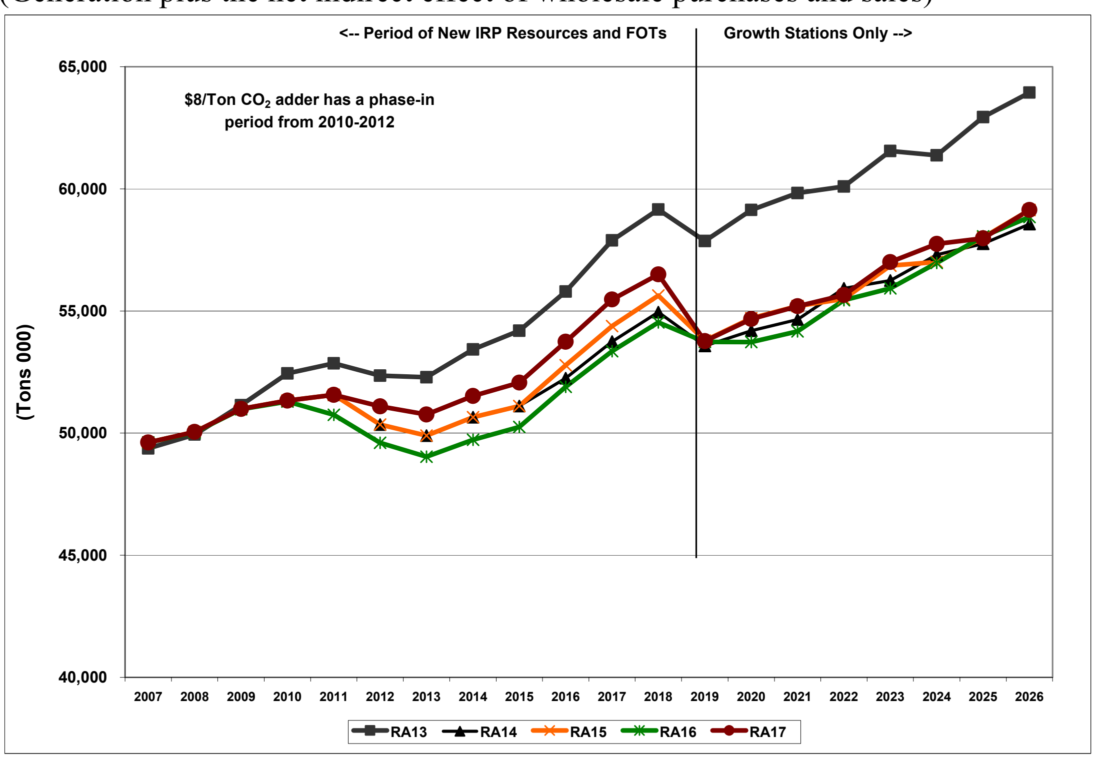
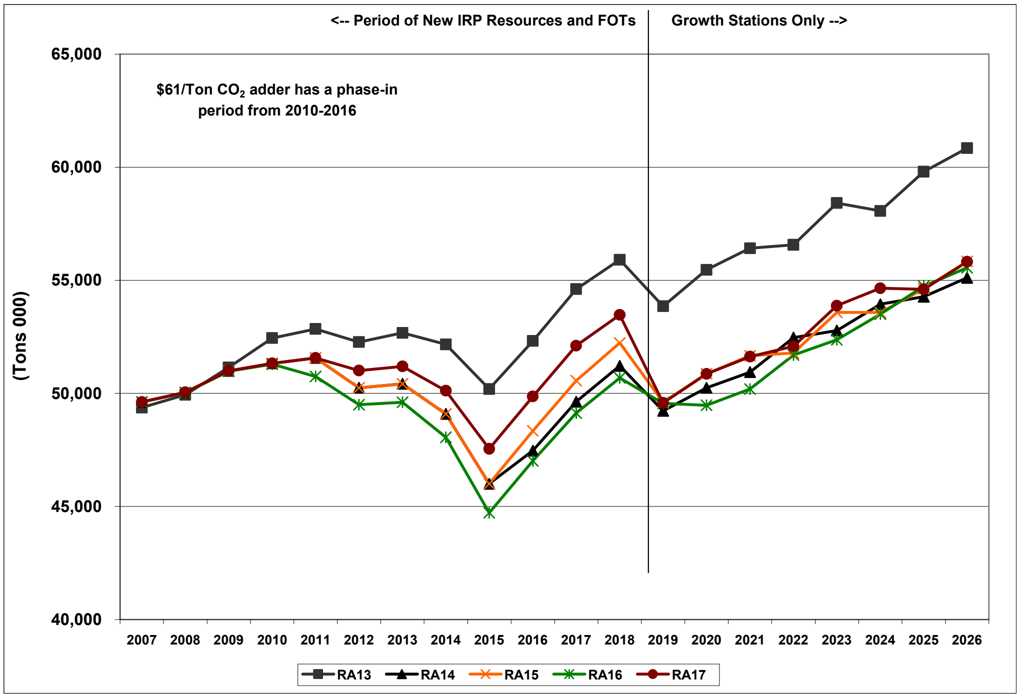


Figure 7.25 – Annual CO_2 Emission Trends, 2007-2026, ($61 CO_2 Adder Case)
(Generation plus the net indirect effect of wholesale purchases and sales)



Figures 7.26 through 7.29 show the annual system CO_2 emissions trends (generation plus net purchases) for 2007 through 2016 by CO_2 adder case, as well as the contributions from generators only.

Figure 7.26 – Annual CO_2 Emissions Trends, 2007-2016 ($8 CO_2 Adder Case)
(From generation only)

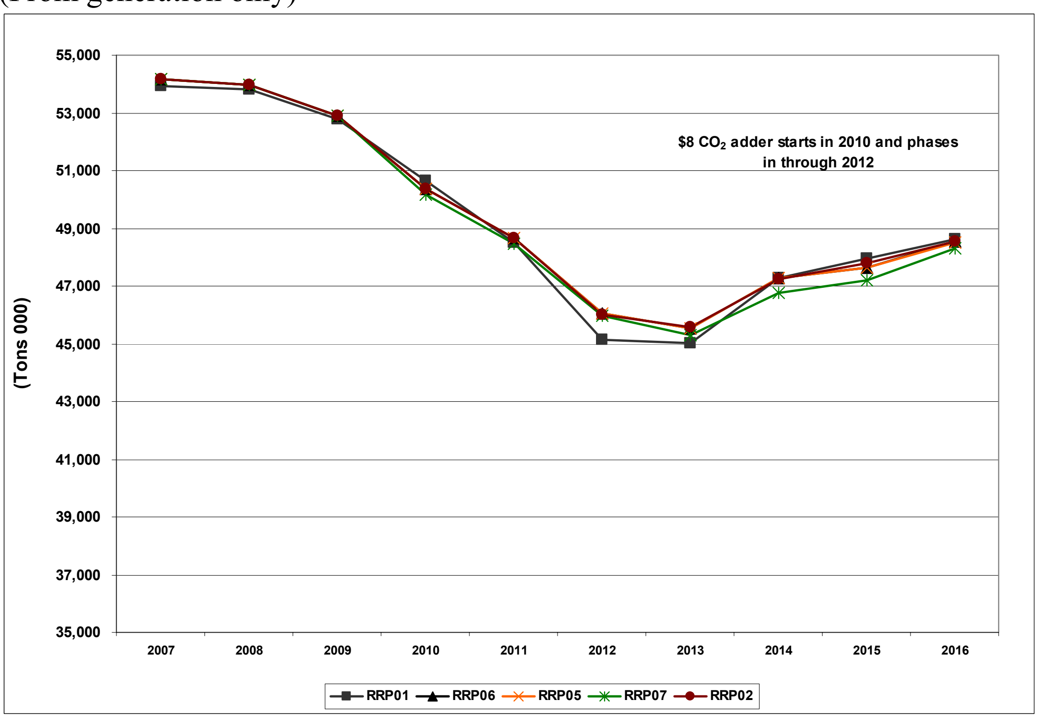


Figure 7.27 – Annual CO_2 Emissions Trends, 2007-2016 ($61 CO_2 Adder Case)
(From generation only)

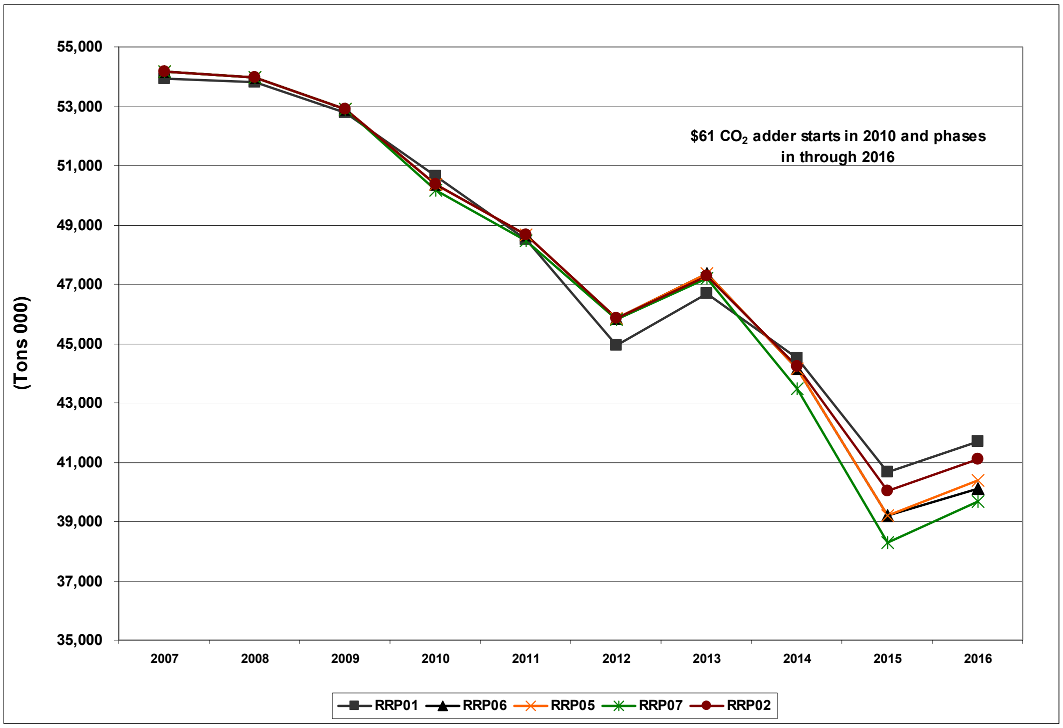


Figure 7.28 – Annual CO_2 Emissions Trends, 2007-2016 ($8 CO_2 Adder Case)
(Generation plus the net indirect effect of wholesale purchases and sales)

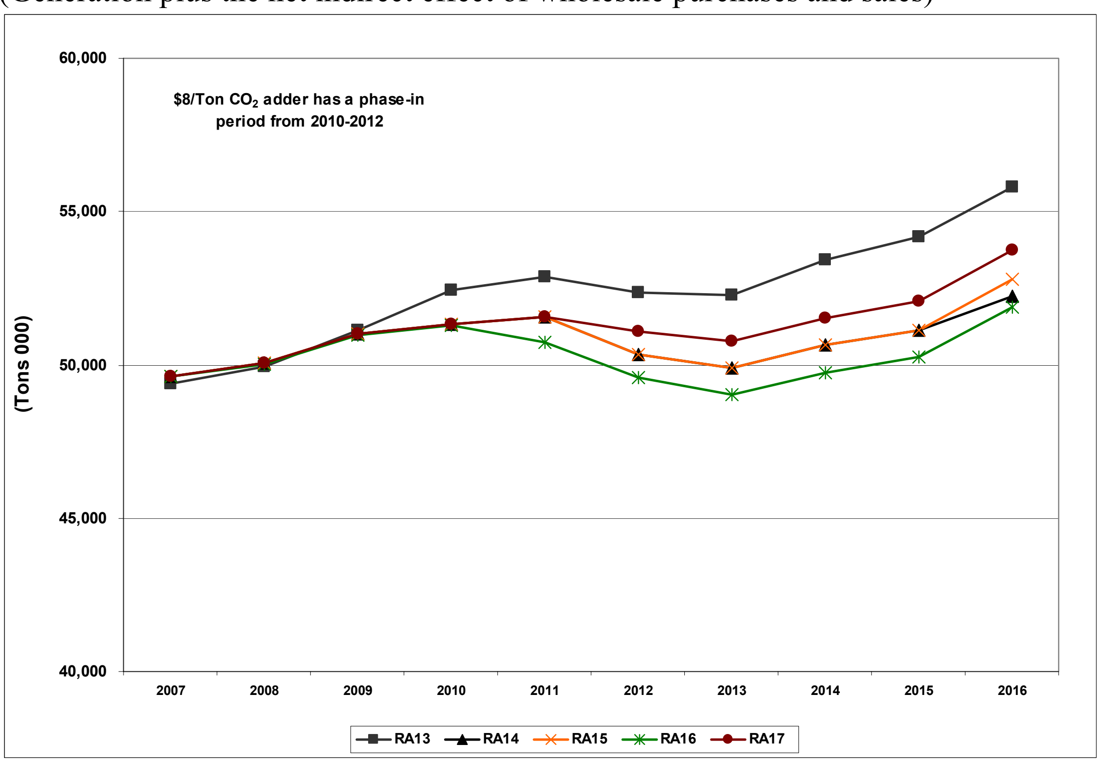


Figure 7.29 – Annual CO_2 Emissions Trends, 2007-2016 ($61 CO_2 Adder Case)
(Generation plus the net indirect effect of wholesale purchases and sales)

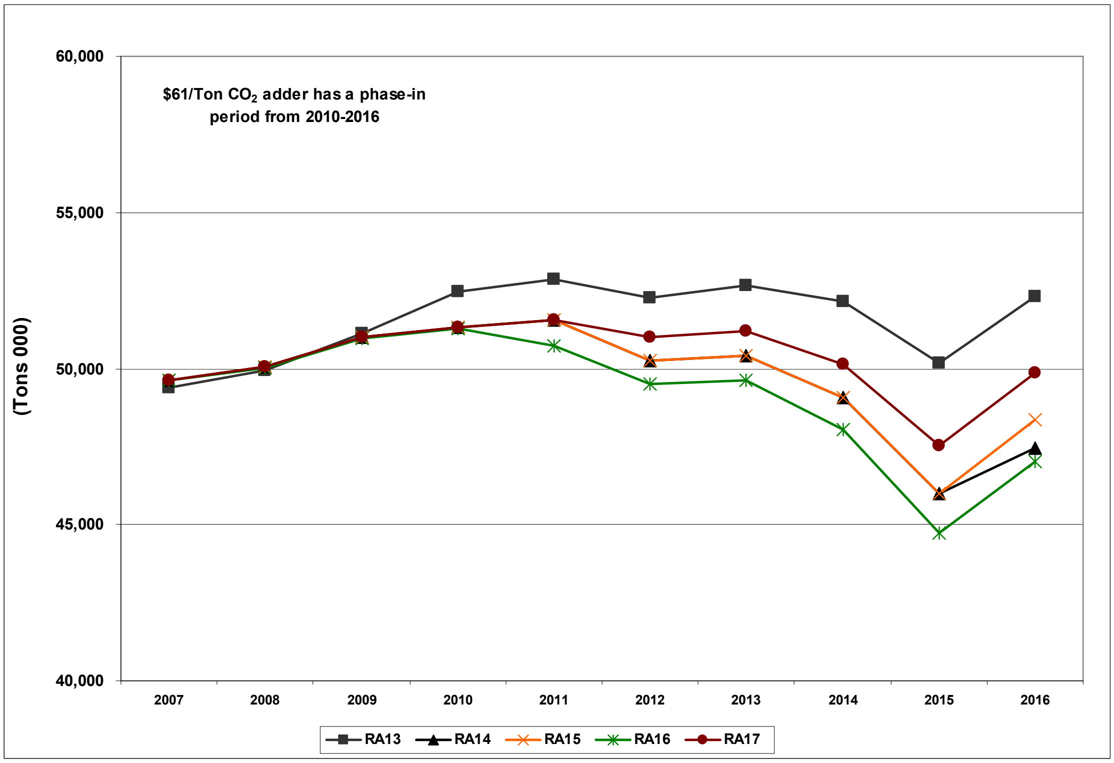


Table 7.41 shows the total portfolio emissions of SO_2, NO_X, mercury, and CO_2 from generators only, by CO_2 adder case, for 2007 through 2026. Portfolio RA16 performed the best across the emission types for most of the CO_2 adder cases. RA2 performed nearly as well, coming in second place on SO_2, NO_X, and mercury emissions for all CO_2 adders except the $61 case.

Table 7.41 – Total Emissions Footprint by CO_2 Adder Case
(From system generation for 2007-2026)

ID	Emission Type and Units			
	SO_2	NO_X	Hg	CO_2
	1000 Tons	1000 Tons	Pounds	1000 Tons
$0 CO_2 Adder Case				
RA13	844	1,196	8,325	1,118,625
RA14	811	1,157	8,048	1,077,417
RA15	814	1,162	8,053	1,079,015
RA16	805	1,148	8,035	1,076,347
RA17	820	1,170	8,056	1,079,240
$8 CO_2 Adder Case				
RA13	803	1,132	8,022	1,064,261
RA14	766	1,088	7,729	1,019,946
RA15	770	1,094	7,735	1,021,983
RA16	759	1,077	7,742	1,017,187
RA17	777	1,104	7,745	1,023,767
$15 CO_2 Adder Case				

ID	Emission Type and Units			
	SO_2 1000 Tons	NO_X 1000 Tons	Hg Pounds	CO_2 1000 Tons
RA13	790	1,111	7,913	1,043,467
RA14	750	1,063	7,615	998,044
RA15	754	1,070	7,623	1,000,419
RA16	742	1,052	7,590	994,806
RA17	762	1,081	7,635	1,002,900
$38 CO_2 Adder Case				
RA13	751	1,047	7,651	996,446
RA14	708	999	7,335	948,247
RA15	712	1,007	7,347	951,276
RA16	699	986	7,306	944,095
RA17	722	1,020	7,367	955,222
$61 CO_2 Adder Case				
RA13	730	1,011	7,529	972,566
RA14	686	964	7,195	922,926
RA15	691	972	7,210	926,375
RA16	677	950	7,163	918,006
RA17	702	987	7,236	931,329

Supply Reliability

Energy Not Served (ENS)

Figures 7.30 and 7.31 show the average annual ENS and upper-tail ENS by portfolio for 2007–2026, respectively. RA16 has the smallest ENS amount at 135 gigawatt hours, followed by RA14. Portfolios RA13 and RA17 have the highest ENS due to the heavier reliance on front of-fice transactions to meet the load obligation. The ENS was also tested for the $0/ton CO_2 and $61/ton CO_2 and the amount of ENS was the same for each portfolio.

Figure 7.30 – Energy Not Served for the $8 CO_2 Adder Case

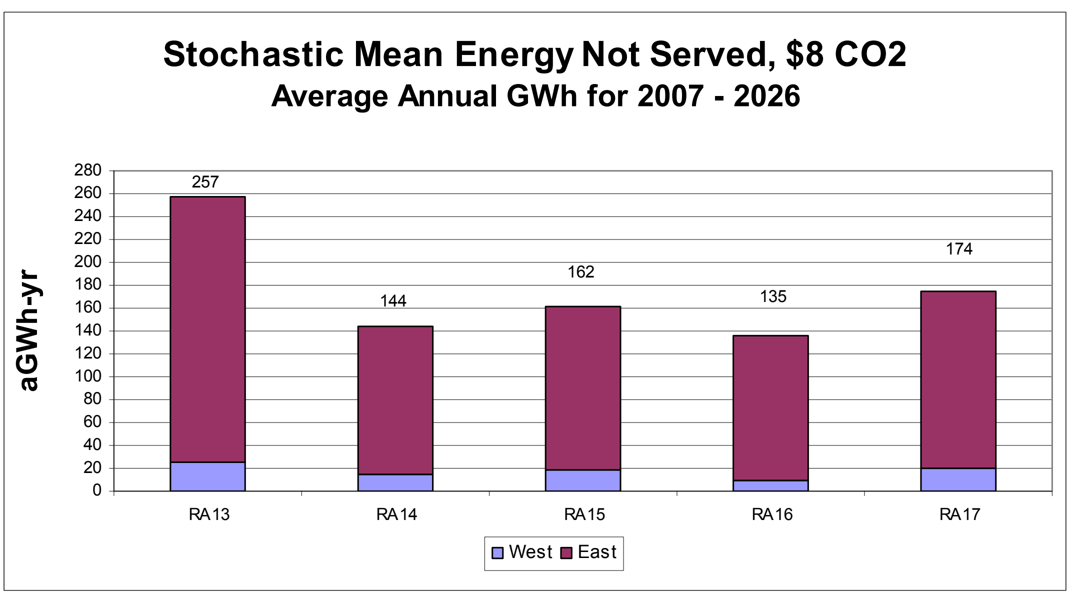
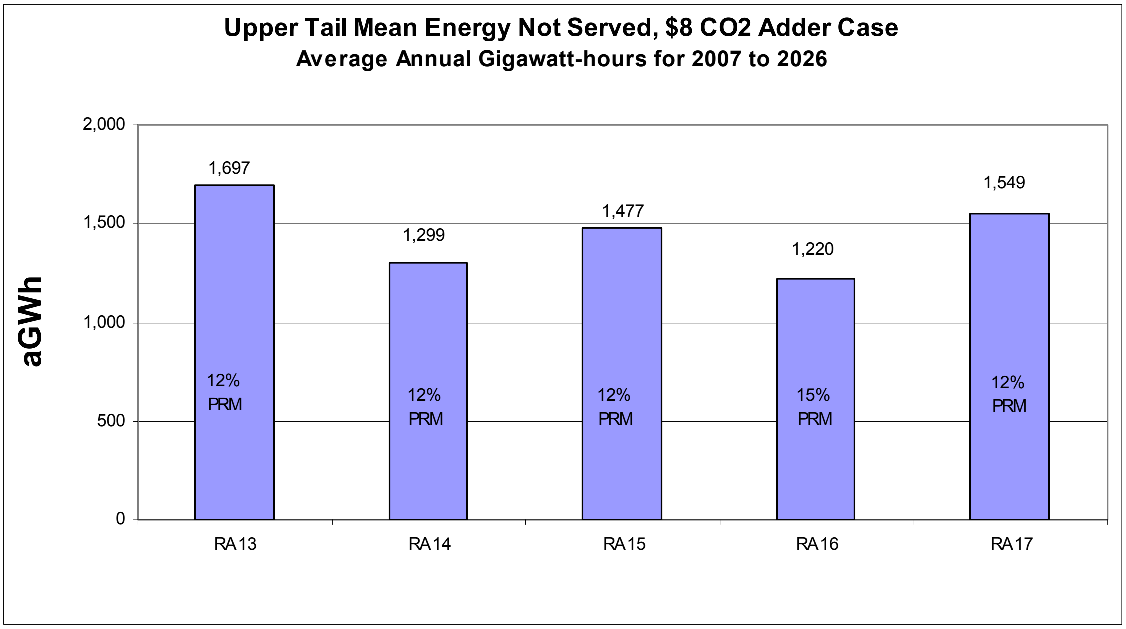


Figure 7.31 – Upper-Tail Mean Energy Not Served for the $8 CO_2 Adder Case



Loss of Load Probability

Table 7.42 displays the average Loss of Load Probability for each of the risk analysis portfolios modeled using the $8 CO_2 adder case. The first block of data is the average LOLP for the first ten years of the study period. The second block of data shows the same information calculated for the entire 20 years. The data is summarized against multiple levels of lost load, which shows the likelihood of losing various amounts of load in a single event.

Table 7.42 – Average Loss of Load Probability During Summer Peak
(Probability of ENS Event > 25,000 MWh in July)

Average for operating years 2007 through 2016					
Event Size (MWh)	RA13	RA14	RA15	RA16	RA17
> 0	29%	24%	25%	23%	26%
> 1,000	24%	22%	22%	20%	24%
> 10,000	16%	14%	15%	13%	17%
> 25,000	12%	11%	11%	9%	13%
> 50,000	9%	8%	8%	6%	10%
> 100,000	6%	5%	5%	4%	7%
> 500,000	1%	1%	1%	0%	1%
> 1,000,000	0%	0%	0%	0%	0%

Average for operating years 2007 through 2026					
Event Size (MWh)	RA13	RA14	RA15	RA16	RA17
> 0	53%	38%	42%	36%	44%
> 1,000	47%	33%	38%	32%	40%
> 10,000	28%	22%	25%	22%	29%
> 25,000	21%	18%	19%	18%	24%

Average for operating years 2007 through 2026					
Event Size (MWh)	RA13	RA14	RA15	RA16	RA17
> 50,000	16%	15%	16%	14%	20%
> 100,000	11%	11%	12%	11%	16%
> 500,000	4%	3%	4%	3%	5%
> 1,000,000	2%	2%	2%	2%	2%

Table 7.43 displays the year-by-year results for the threshold value of 25,000 megawatt-hours. For each year, the LOLP value represents the proportion of the 100 iterations where the July ENS was greater than 25,000 megawatt-hours. This is the equivalent of 2,500 megawatts for 10 hours.

Table 7.43 – Year-by-Year Loss of Load Probability

Year	RA13	RA14	RA15	RA16	RA17
2007	1%	2%	2%	2%	2%
2008	3%	3%	3%	3%	3%
2009	8%	10%	10%	10%	10%
2010	13%	12%	12%	13%	12%
2011	16%	16%	16%	10%	16%
2012	7%	7%	7%	4%	9%
2013	13%	12%	12%	8%	13%
2014	15%	10%	10%	8%	16%
2015	23%	18%	18%	15%	22%
2016	20%	16%	20%	17%	26%
2017	23%	26%	29%	25%	30%
2018	28%	26%	30%	27%	39%
2019	15%	18%	19%	20%	30%
2020	22%	23%	27%	25%	31%
2021	24%	22%	25%	23%	33%
2022	32%	29%	31%	34%	38%
2023	28%	23%	28%	22%	36%
2024	36%	25%	27%	30%	36%
2025	41%	28%	33%	32%	32%
2026	49%	28%	28%	29%	37%

STOCHASTIC SIMULATION SENSITIVITY ANALYSES

PacifiCorp performed several stochastic simulation studies to test the stochastic cost, risk, and reliability impacts of planning reserve margin and resource type assumptions against a reference portfolio. Table 7.44 lists the sensitivity analysis studies conducted and the reference portfolios used. The study assumptions and results are summarized below.

Table 7.44 – Sensitivity Analysis Scenarios for Detailed Simulation Analysis

#	Name	Reference Case
1	Plan to a 12% capacity reserve margin, and include Class 3 DSM sufficient to eliminate ENS	RA8 (Consistent with the portfolio developed for SAS01)
2	Plan to 18% capacity reserve margin	SAS02, "Plan to 18% capacity reserve margin"
3	Replace a 2012 base load resource with front office transactions	Risk Analysis Portfolio RA1
4	Replace a base load pulverized coal resource with a carbon-capture-ready IGCC resource	Risk Analysis Portfolio RA1
5	Substitute a base load resource with CHP and aggregated dispatchable customer standby generation	Risk Analysis Portfolio RA1

12-Percent Planning Reserve Margin with Class 3 Demand-side Management Programs

For this study, 106 megawatts of Class 3 demand side management programs were added to the RA8 risk analysis portfolio in 2009. This DSM quantity reflects the total available to the model according to the base case proxy supply curve results reported by Quantec LLC, and includes capacity for curtailable rate, critical peak pricing, and demand buyback programs for both the east and west sides of the system. The Class 3 DSM programs were modeled in the PaR module as a “take” component during super-peak hours and a “return” component for all other hours.

The impact of the Class 3 DSM on portfolio performance was negligible. Compared to RA8, stochastic mean PVRR increased by $11 million, risk exposure decreased by $9 million, and Energy Not Served decreased by 0.1 percent.

Plan to an 18-Percent Planning Reserve Margin

PacifiCorp modeled the CEM investment plan that resulted from planning to an 18-percent planning reserve margin (SAS02 study). The SAS02 study reflects the same scenario conditions as RA1 except for the 15-percent planning reserve margin. Relative to RA1, the SAS02 portfolio resulted in a $69 million increase in stochastic mean PVRR, while risk exposure decreased by $346 million. Energy Not Served also decreased by about 16 percent. The PVRR increase was mainly attributable to the addition of an east SCCT frame resource.

Replace a 2012 Base Load Resource with Front Office Transactions

Using RA1 as the reference case, PacifiCorp replaced the small Utah pulverized coal resource acquired in 2012 (340 megawatts) with a comparable amount of front office transactions acquired at the Mona trading location (6x16 product over 3 month summer season) that continued over the remaining study period.

Compared to RA1, the new portfolio’s stochastic mean PVRR was $4 million lower, while the risk exposure increased by $3.4 billion. Energy Not Served increased by nine percent. Based on this sensitivity study, PacifiCorp concluded that replacing a long-term asset outright with market purchases—holding other factors constant—is not a preferred east-side resource strategy given the cost-versus-risk tradeoff.

Replace a Base Load Pulverized Coal Resource with a Carbon-Capture-Ready IGCC

Starting with portfolio RA1, PacifiCorp replaced the 750-megawatt Wyoming supercritical pulverized coal resource with an equivalently sized IGCC plant that has minimum carbon capture provisions. The coal resource replacement resulted in a $687 million increase in stochastic mean PVRR and a $411 million increase in risk exposure. The risk exposure increase is due to the two-percent lower availability of the IGCC relative to the Wyoming SCPC resource.

Replace a Base Load Resource with CHP and Dispatchable Customer Standby Generation

Using portfolio RA1 as the starting point, PacifiCorp replaced the small Utah pulverized coal resource with 280 megawatts of gas-fired CHP resources and 60 megawatts of west-side customer standby generation. (This sensitivity addresses an analysis requirement in the Oregon Public Utility Commission's 2004 Integrated Resource Plan acknowledgement order.) Table 7.45 reports the sizes, locations, and number of units used for the study.

Table 7.45 – Combined Heat and Power Replacement Resources

CHP Resource Type	East Location	West Location	System Total
Large industrial – 25 MW	75 MW (3 units)	150 MW (6 units)	225 MW (9 units)
Small industrial/commercial – 5 MW	35 MW (7 units)	20 MW (4 units)	55 MW (11 Units)
Total	**110 MW**	**170 MW**	**280 MW**

Comparing against portfolio RA1, the new portfolio with CHP and customer standby generation resources had a $168 million higher stochastic mean PVRR. Risk exposure was higher by $2.4 billion, while Energy Not Served was higher by about 7 percent.

PREFERRED PORTFOLIO SELECTION AND JUSTIFICATION

Based on the stochastic analysis results for the Group 2 risk analysis portfolios, the company has chosen RA14 as the preferred portfolio. Table 7.46 shows the resulting load and resource balance with preferred portfolio resources and east-west transfers included.

This portfolio reflects a robust resource strategy that accounts for the major resource risk factors (specifically the form and cost impact of CO_2 regulations, and price volatility for natural gas plants and market purchases) as well as evolving state resource policies that are currently not coordinated with respect to PacifiCorp's system-wide integrated resource planning mandate. Portfolio RA14 is viewed as the least-cost and least economically risky proposition for reliably meeting PacifiCorp's load obligation while accommodating different state policies and interests.

In assessing the overall merits of this portfolio, PacifiCorp also concentrated on the value of the different resource types for managing portfolio risks in the short term, mid term, and long term. For the short term, the acquisition of renewables, DSM and CHP increases portfolio diversity and lays the groundwork for a resource base that can comply with early RPS and CO_2 compliance schedules. For the mid term—2012 through 2014, which is a period marked by significant resource need and escalating regulatory risks—the preferred portfolio is constituted with a mix of proxy long-term assets with complementary risk profiles (supercritical pulverized coal and CCCT resources), supplemented by new front office transactions to increase planning flexibility. For the long term, the preferred portfolio includes flexible long-term assets with a small emissions footprint and a moderate reliance on front office transactions. This resource mix is most in line with the company strategy to reduce its long-term reliance on the market, which is discussed in more detail later in this chapter.

Planning Reserve Margin Selection

While Portfolio RA14 is based on a target planning reserve margin of 12 percent, PacifiCorp is targeting a reserve margin range of 12 to 15 percent to increase planning flexibility given a time of rapid public policy evolution and wide uncertainty over the resulting down-stream cost impacts. While the portfolio analysis indicates that lowering the planning reserve margin increases portfolio stochastic risk and reduces reliability, the decision on what margin to adopt is a subjective one that depends on balancing portfolio risk against cost. Given the expected pressure on customer rates due to state resource constraints, as well as the rapid pace of construction cost increases for all resource types, near-term affordability of a resource plan is a consideration guiding the planning margin decision.

PacifiCorp's choice to adopt a 12 percent planning reserve margin is intended to keep the portfolio cost down while retaining the flexibility to adjust the margin upwards and acquire appropriate incremental resources. Market conditions, revised load growth projections, or new regional adequacy standards may prompt the company to increase the margin in response. Based on the Group 2 portfolio analysis and the resource outlook developed for this IRP, a higher planning reserve margin would be met with a combination of gas generation and front office transactions, as can be seen in Portfolio RA16.

An issue raised by public stakeholders is the impact of the planning reserve margin decision on supply reliability. PacifiCorp's view is that supply reliability is not materially impacted by a swing in the margin from 15 to 12 percent. The supply reliability analyses (Energy Not Served and Loss of Load Probability) indicate that, with the exception of "all coal" portfolios such as RA13, there are no significant differences among the portfolios with respect to reliability. As additional evidence of this finding, comparing portfolio pairs intended to test the impact of a 15 percent margin against a 12 percent margin (RA1 versus RA8, RA10 versus RA9, RA11 versus RA12, and RA16 versus RA14) yields small differences in average annual ENS of between 1.2 MWa to 3.9 MWa.

Table 7.46 – Preferred Portfolio Capacity Load and Resource Balance

Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
East										
Thermal	6,134	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	153	163	163	163	163	163	163	163	163	163
Renewable	65	109	109	109	109	109	109	109	105	105
Purchase	904	679	778	548	543	343	343	343	343	322
QF	106	106	106	106	106	106	106	106	106	106
Interruptible	233	233	308	308	308	308	308	308	308	308
Transfers	534	797	731	898	1,162	955	1,111	597	701	777
East Existing Resources	8,264	8,163	8,271	8,208	8,467	8,060	8,216	7,702	7,802	7,857
Wind	0	24	24	40	48	48	109	109	109	109
DSM	0	0	0	0	0	15	63	63	63	63
CHP	0	0	0	0	0	25	25	25	25	25
Front Office Transactions	0	0	0	393	272	97	3	149	192	165
Thermal	0	0	0	0	0	888	888	1,415	1,415	1,772
East Planned Resources	0	24	24	433	320	1,073	1,088	1,761	1,804	2,134
East Total Resources	8,264	8,187	8,295	8,641	8,787	9,133	9,304	9,463	9,606	9,991
Load	6,321	6,515	6,657	7,137	7,289	7,595	7,738	7,895	8,026	8,366
Sale	849	811	702	666	631	595	595	595	595	595
East Obligation	7,170	7,326	7,359	7,803	7,920	8,190	8,333	8,490	8,621	8,961
Planning reserves (12%)	706	750	733	767	796	872	894	896	906	953
Non-owned reserves	71	71	71	71	71	71	71	71	71	71
East Reserves	776	821	804	837	867	942	965	966	977	1,023
st Obligation + Reserves (12%)	7,946	8,147	8,163	8,641	8,787	9,132	9,298	9,456	9,598	9,984
East Position	317	40	132	0	0	1	6	7	8	6
East Reserve Margin	16%	13%	14%	12%	12%	12%	12%	12%	12%	12%
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,421	1,414	1,328	1,357	1,225	1,249	1,243	1,244	1,242
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	108	108	108	108	108	84	84	84	84	84
Purchase	786	800	800	799	749	112	141	107	107	107
QF	40	40	40	40	40	40	38	38	38	38
Transfers	(542)	(804)	(741)	(907)	(1,170)	(964)	(1,120)	(606)	(708)	(786)
West Existing Resources	3,859	3,611	3,667	3,414	3,130	2,542	2,438	2,913	2,811	2,732
Wind	14	14	51	79	79	98	98	98	98	98
DSM	0	0	0	0	0	32	32	32	32	32
CHP	0	0	0	0	0	75	75	75	75	75
Front Office Transactions	0	0	0	219	64	555	657	247	246	249
Thermal	0	0	0	0	548	548	548	548	548	548
West Planned Resources	14	14	51	298	691	1,308	1,410	1,000	999	1,002
West Total Resources	3,873	3,625	3,718	3,712	3,821	3,850	3,848	3,913	3,810	3,734
Load	2,922	2,924	3,095	3,124	3,199	3,240	3,251	3,262	3,271	3,252
Sale	299	299	299	290	290	258	258	258	158	108
West Obligation	3,221	3,223	3,394	3,414	3,489	3,498	3,509	3,520	3,429	3,360
Planning Reserves (12%)	292	291	311	287	321	336	322	376	365	357
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	299	297	318	294	328	342	328	383	372	363
West Obligation + Reserves	3,513	3,514	3,705	3,701	3,810	3,834	3,831	3,896	3,794	3,716
West Position	360	111	12	11	11	16	17	17	16	18
West Reserve Margin	23%	15%	12%	12%	12%	12%	12%	12%	12%	12%
System										
Total Resources	12,137	11,811	12,013	12,353	12,608	12,983	13,152	13,376	13,416	13,725
Obligation	10,391	10,549	10,753	11,217	11,409	11,688	11,842	12,010	12,050	12,321
Reserves	1,075	1,118	1,122	1,131	1,194	1,285	1,293	1,349	1,348	1,386
Obligation + Reserves	11,466	11,667	11,874	12,348	12,603	12,973	13,135	13,359	13,398	13,707
System Position	671	144	138	5	5	10	17	17	18	18
Reserve Margin	18%	13%	13%	12%	12%	12%	12%	12%	12%	12%

The Role of Front Office Transactions and Market Availability Considerations

In parallel with the decision on an appropriate planning reserve margin level, the degree to which PacifiCorp relies on firm market transactions is a decision that requires balancing portfolio cost and risk. As demonstrated by comparing risk analysis portfolios with differing front office transaction assumptions, less reliance on front office transactions tends to reduce market price risk exposure, but can increase or decrease mean stochastic cost depending on the make-up of the portfolio. As mentioned earlier in this chapter, PacifiCorp believes that a limited amount of front office transactions benefit the preferred portfolio by increasing planning flexibility and resource diversity. Nevertheless, the company is concerned about long-term reliance on the market and exposure to market price risk, and therefore seeks to reduce that reliance as part of its overall resource management strategy. This concern stems from two sources of market price risk and uncertainty. The first source is the shifting resource mix outlook in the Western Interconnection, driven principally by new or expected state regulatory requirements. Specific trends include extensive expansion of renewable and gas-fired capacity and a counterpart reduction in coal capacity development. The second source of risk and uncertainty is the potential tightening of the regional capacity balance in the next decade due to planned resources not being built as more utilities rely on the market to meet their future needs. This is the time frame when a significant amount of base load capacity is needed by PacifiCorp and other utilities.

The preferred portfolio is consistent with this strategic view on market reliance. The system-wide front office transaction amount in the preferred portfolio peaks at 660 megawatts in 2013, representing just over 55 percent of the transactions amount included as a planned resource in PacifiCorp's 2004 IRP (1,200 megawatts). Additionally, the company no longer plans for a fixed annual target amount of new firm market purchases in the load and resource balance as was done for the previous IRP; rather, front office transactions are evaluated on a comparable basis with other resources and are subject to the company's stochastic risk analysis. Finally, the reliance on front office transactions drops off significantly after 2013, declining over one-third by 2016.

Regarding market availability to support the level of front office transactions in the preferred portfolio, PacifiCorp points to purchase offer activity in response to recent periodic requests for proposals issued by the company's commercial and trading department. Requests in 2007 for third-quarter products for 2007-2012 delivery yielded over 5,000 megawatts in offers.

FUEL DIVERSITY PLANNING

Pursuant to the Utah Public Service Commission's order on the PURPA Fuel Source Standard (Docket no. 06-999-03, issued on March 13, 2007), this section describes how fuel source diversity is addressed in the 2007 Integrated Resource Plan.[63]

The IRP standards and guidelines require PacifiCorp to evaluate all resource options on a consistent and comparable basis, which explicitly implies consideration of coal, natural gas, demand-side management, and renewable resources (See Appendix I). In addition, the new Oregon Public

[63] As directed by the Utah Commission and agreed to by PacifiCorp, all future IRPs will include a section on fuel source diversity to comply with the new fuel source standard under Title 1 Subtitle B of PURPA. See Chapter 3 for more details.

Utility Commission IRP guidelines issued in January 2007 require the company to consider "all known resources for meeting the utility's load", as well as compare different fuel types.[64] As discussed in Chapter 2, one of PacifiCorp's planning principles is to seek a diversified, low-cost mix of resources that minimizes risks for customers and the company. The company's portfolio optimization studies, using a range of planning scenarios, adhered to this planning principle.

This IRP fulfills the PURPA requirement for a fuel diversity plan in the following ways:

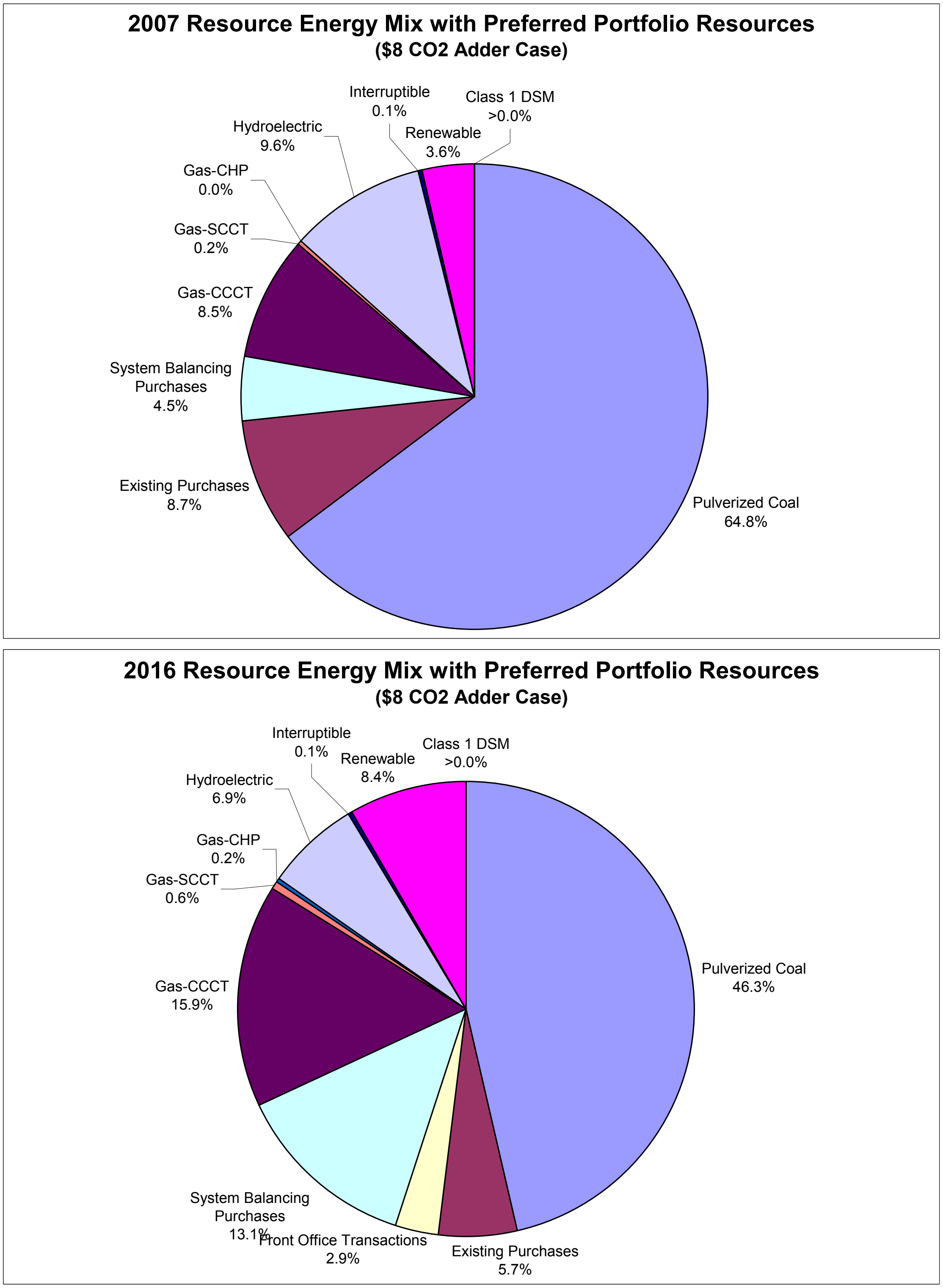
- PacifiCorp considered a comprehensive range of resource options for the IRP, including transmission resources. With the exception of Class 2 DSM, these resources were evaluated on a comparable basis using the CEM model.
- PacifiCorp conducted alternative future studies to derive optimal resource investment plans under a wide range of conditions. As a result of these deterministic scenario studies, PacifiCorp selected a variety of DSM programs, wind, and CHP resources to be included in subsequent portfolio evaluations and the preferred portfolio.
- To account for state resource policies in the areas of renewable generation and climate change, the company evaluated portfolios with an additional 600 megawatts of nameplate wind capacity. Based on the associated stochastic modeling results, PacifiCorp decided to include this additional wind capacity in its preferred portfolio.[65]
- PacifiCorp validated with its stochastic production cost modeling that a balanced mixture of new wind, gas, and coal resources is optimal from a cost and portfolio risk management standpoint.
- Although the preferred portfolio includes 867 megawatts of supercritical pulverized coal capacity, the amount of natural gas-fired capacity added exceeds this amount (1,553 megawatts) as does the nameplate renewables capacity (2,000 megawatts).

Figure 7.32 compares the resource energy mix for 2007 and 2016; the latter including preferred portfolio resources. The 2016 results are shown for generation under an \$8/ton CO_2 adder and the average generation across the five CO_2 adders modeled. The comparison highlights the large decrease in coal-fired generation and the offsetting increase in renewable, gas-fired, and front office transaction generation. (Note that only the system balancing purchases are shown; for example, under the \$8/ton CO_2 adder case, accounting for system balancing sales results in a net sales amount of 9,843 gigawatt-hours in 2007 and a net purchase amount of 3,518 gigawatt-hours in 2016.)

Figure 7.33 provides a resource mix comparison on the basis of capacity for the \$8/ton CO_2 adder case. For the renewables category, the capacity contribution of wind resources is used.

[64] Public Utility Commission of Oregon, "Investigation Into Integrated Resource Planning" UM 1056, Order No. 07-002, Appendix A, p. 7.
[65] The preferred portfolio was also tested to determine the cost and risk impact of removing the 600 MW of wind. Stochastic PVRR increased by \$0.9 billion and risk exposure increased by \$5.5 billion due to the increase in spot market purchases.

Figure 7.32 – Current and Projected PacifiCorp Resource Energy Mix



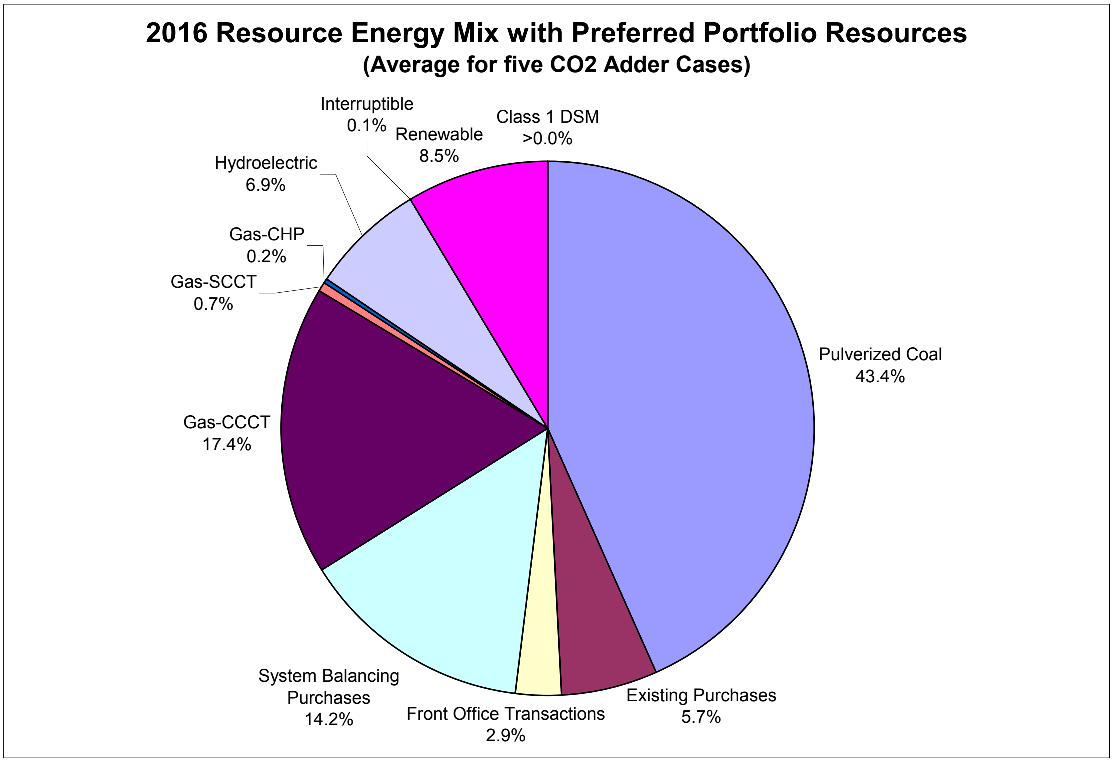
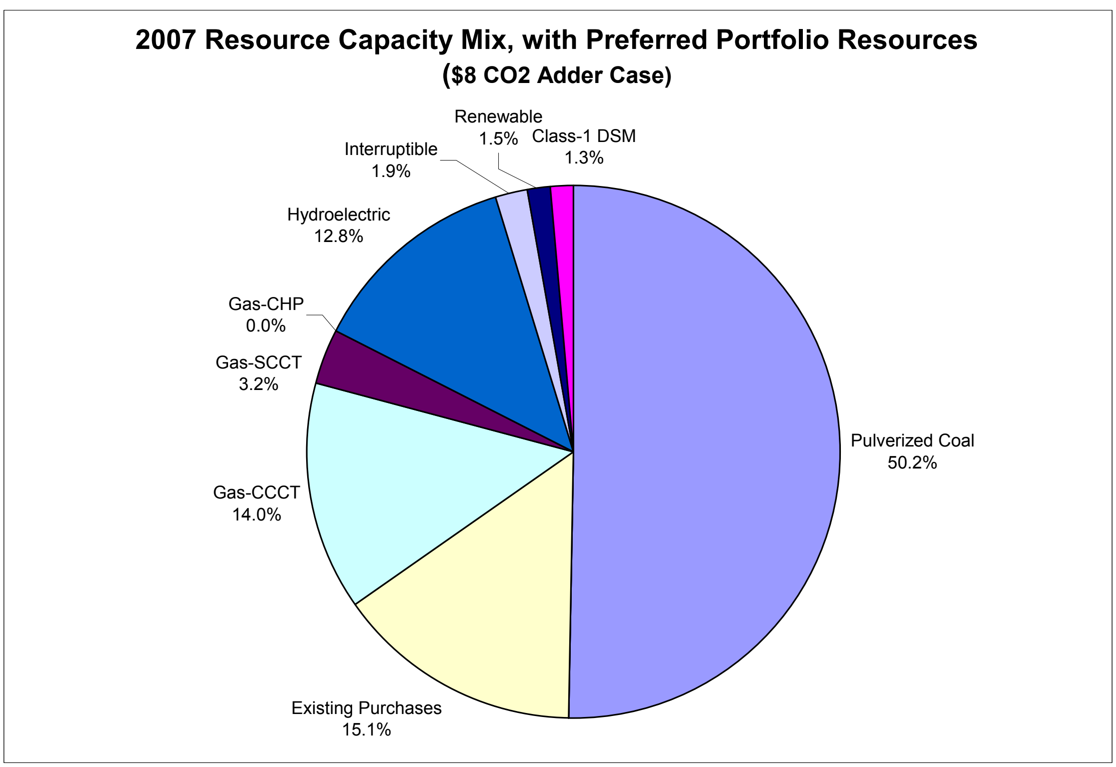
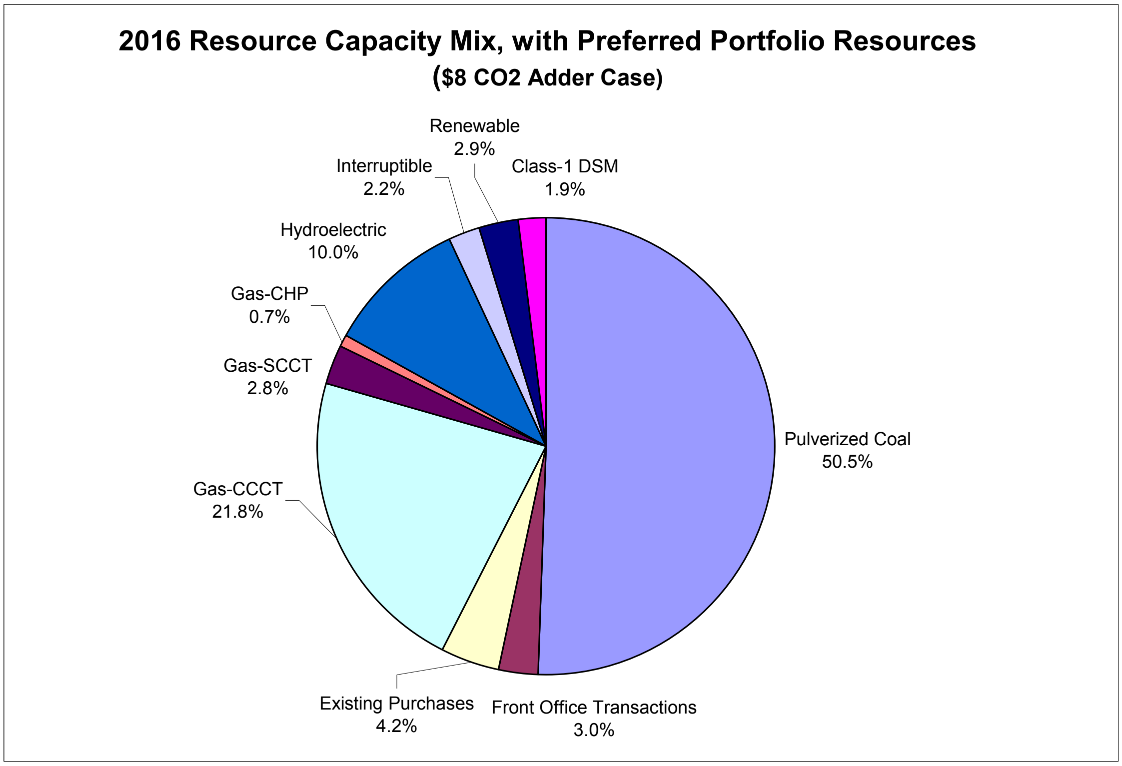


Figure 7.33 – Current and Projected PacifiCorp Resource Capacity Mix



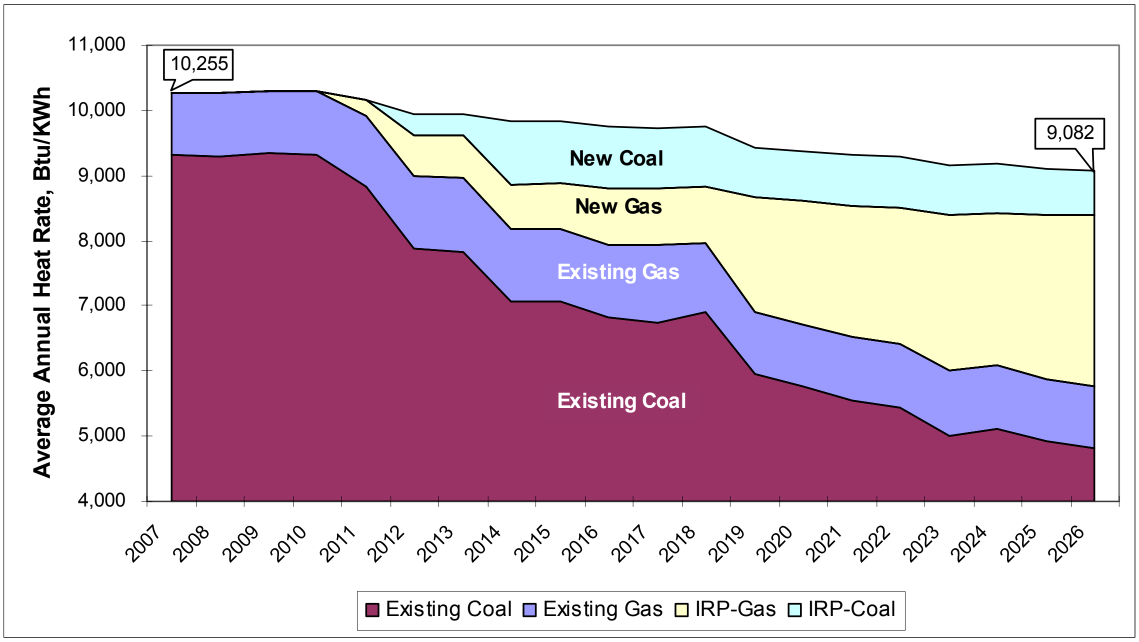


FORECASTED FOSSIL FUEL GENERATOR HEAT RATE TREND

Pursuant to the Utah Public Service Commission's order on the PURPA Fuel Sources Standard (Docket no. 06-999-03), this section reports the forecasted average heat rate trend for the company's fossil fuel generator fleet on an annual basis, accounting for new IRP resources and current planned retirements of existing resources. The fleet-wide heat rate represents the individual generator heat rates weighted by their annual generation. (Note that system dispatch accounts for an $8/ton CO_2 cost adder). For existing fossil fuel resources, four-year average historical heat rate curves are used, whereas new resources use expected heat rates accounting for degradation over time.

Figure 7.34 shows the fleet weighted-average fossil fuel generator heat rate trend from 2007 through 2026, indicating the contributions from existing coal resources, existing gas resources, new coal resources, and new gas resources (including CHP). The average heat rate declines from 10,255 to 9,082 Btu/kWh, a compounded average annual decrease of 0.6 percent. As indicated in Figure 7.34, the heat rate contribution of existing coal plants drops significantly, declining from 91 percent of the system total in 2007 to only 53 percent by 2026. Also underlying the trend is increasing reliance on generation from new gas and wind resources, the later displacing generation from existing coal plants.

Figure 7.34 – Fleet Average Fossil Fuel Heat Rate Annual Trend by Generator Type



CLASS 2 DSM DECREMENT ANALYSIS

This section presents the results of the Class 2 demand-side management decrement analysis. For this analysis, the preferred portfolio, RA14, was used to calculate the decrement value of various types of Class 2 programs following the methodology described in Chapter 6. PacifiCorp will use these decrement values when evaluating the cost-effectiveness of potential new programs between IRP cycles. Note that for the next IRP, the company intends to model Class 2 DSM programs as options in the CEM.

Modeling Results

Tables 7.47 and 7.48 show the nominal results of the 12 decrement cases for each year of the 20-year study period. Although no resources were deferred or eliminated from the portfolio due to the addition of Class 2 decrements, there is value in having to produce less generation to meet a smaller load. Consistent with the results for the 2004 IRP, the residential air conditioning decrements produce the highest value for both the east and west locations. The commercial lighting, residential lighting, and system load shapes provide the lowest avoided costs. Much of their end use shapes reduce loads during a greater percentage of off-peak hours than the other shapes and during all seasons, not just the summer.

Table 7.47 – Annual Nominal Avoided Costs for Decrements, 2010-2017

Decrement Name	Actual Load Factor	Decrement Values (Nominal $/MWh)							
		2010	2011	2012	2013	2014	2015	2016	2017
EAST									
Residential Cooling	7%	113.38	108.78	87.59	102.59	93.54	103.99	109.84	125.48
Residential Lighting	60%	68.98	71.73	59.68	62.57	59.64	64.99	70.69	79.62
Residential Whole House	46%	70.15	72.66	59.42	62.88	60.20	65.45	70.96	80.75
Commercial Cooling	16%	84.24	85.30	69.27	71.34	67.94	73.62	80.28	92.47
Commercial Lighting	49%	68.54	71.97	58.73	61.46	58.68	63.41	69.75	78.65
System Load Shape	65%	65.18	68.16	56.32	59.07	56.47	61.24	67.18	75.95
WEST									
Residential Cooling	20%	53.78	51.87	46.99	48.02	53.67	61.06	64.64	71.75
Residential Heating	28%	39.61	51.06	46.11	41.06	46.09	49.83	58.15	62.73
Residential Lighting	60%	44.34	48.56	43.70	42.10	47.45	52.78	58.20	64.16
Commercial Cooling	16%	51.66	51.53	46.13	45.39	50.85	56.96	61.81	68.73
Commercial Lighting	49%	43.70	49.34	44.49	42.02	47.47	53.32	59.31	64.67
System Load Shape	67%	43.30	47.26	42.03	40.37	45.83	50.94	56.26	61.72

Table 7.48 – Annual Nominal Avoided Costs for Decrements, 2018-2026

Decrement Name	Decrement Values (Nominal $/MWh)								
	2018	2019	2020	2021	2022	2023	2024	2025	2026
EAST									
Residential Cooling	159.57	126.86	134.61	143.92	156.62.	162.45	179.23	163.99	169.83
Residential Lighting	89.48	79.87	84.65	94.16	101.92	107.82	114.58	109.87	114.15
Residential Whole House	92.15	80.99	86.70	96.72	104.36	109.46	115.60	110.67	115.30
Commercial Cooling	112.19	94.43	101.17	112.70	120.17	127.26	134.85	125.33	130.80
Commercial Lighting	88.24	79.76	84.34	93.77	102.27	107.34	112.81	108.90	113.99
System Load Shape	85.11	76.64	81.36	91.08	98.25	103.65	109.32	106.14	110.51
WEST									
Residential Cooling	82.31	84.03	81.81	84.23	88.84	92.96	92.68	101.82	106.02
Residential Heating	64.95	74.27	73.25	75.52	77.45	83.09	83.53	87.11	90.81
Residential Lighting	69.12	75.11	74.60	77.29	80.09	83.49	84.27	90.13	92.83
Commercial Cooling	79.65	81.63	79.24	82.88	85.36	89.09	89.94	99.11	102.64
Commercial Lighting	69.44	76.45	75.28	78.62	81.44	85.47	86.40	91.81	94.13
System Load Shape	66.44	73.25	72.82	75.55	77.92	81.97	82.64	87.95	90.18

Figures 7.35 and 7.36 show the decrement costs for each end use along with the average annual forward market price for that location: Palo Verde (PV) for the east and Mid-Columbia (Mid-C) for the west.

Figure 7.35 – East Decrement Price Trends

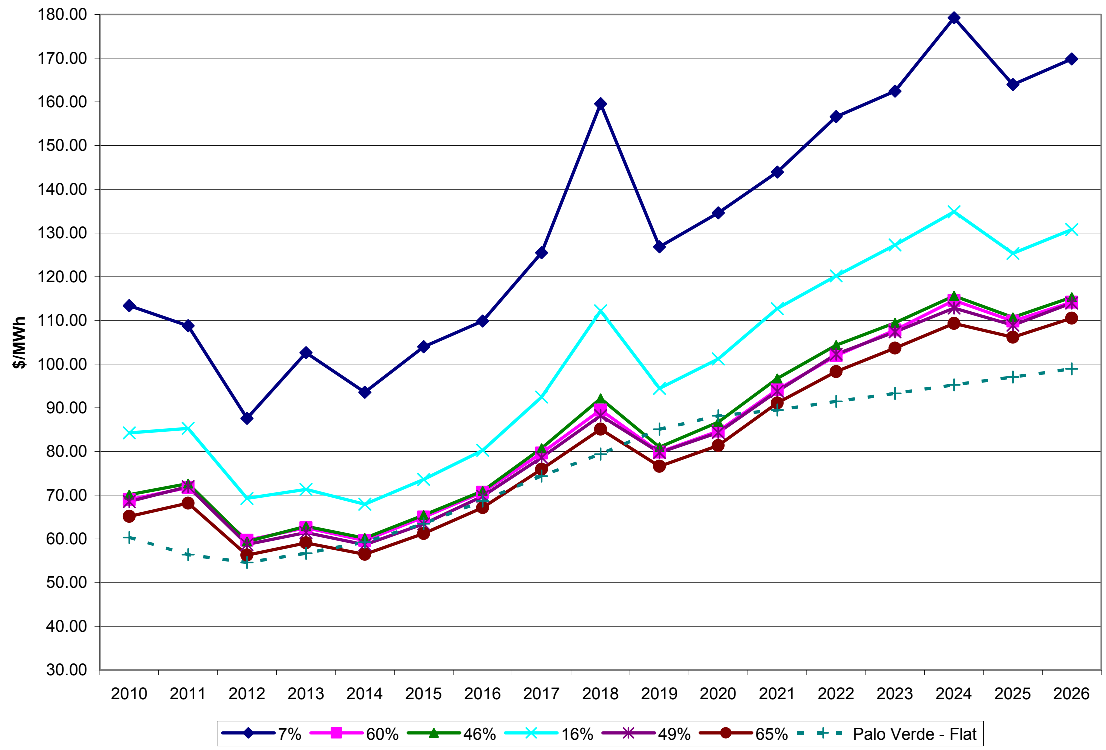
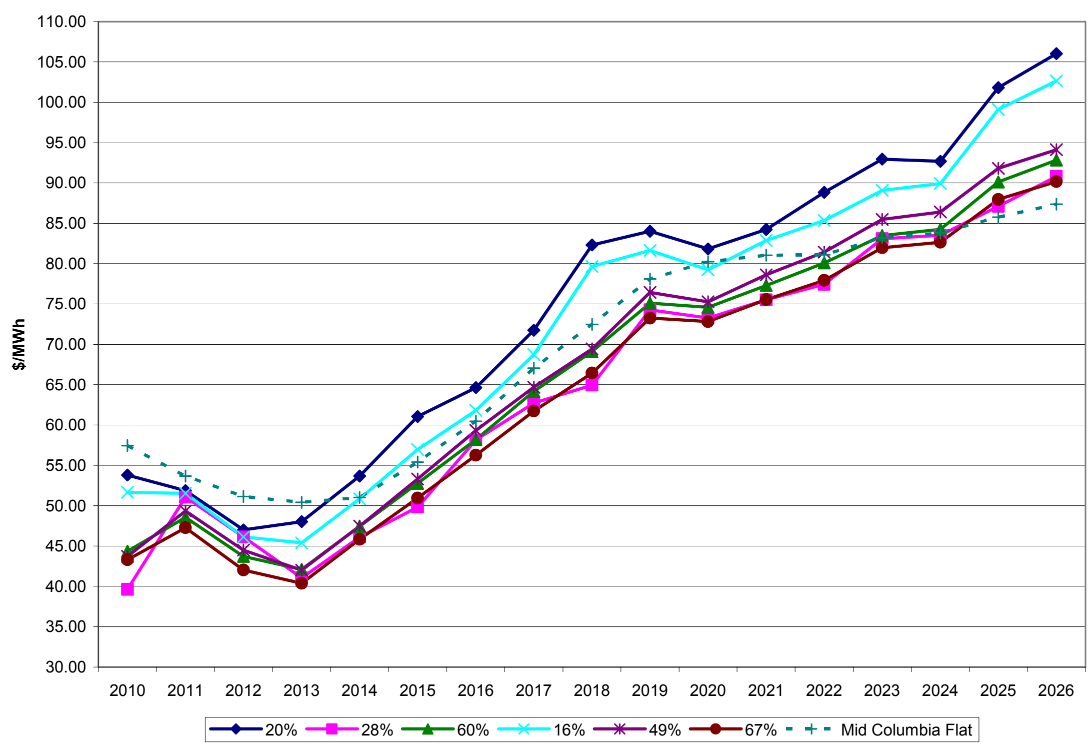


Figure 7.36 – West Decrement Price Trends



REGULATORY SCENARIO RISK ANALYSIS – GREENHOUSE GAS EMISSIONS PERFORMANCE STANDARDS

Chapter 2 identified CO_2 regulation as an important scenario risk facing the company. In addition to the CO_2 externality cost scenarios investigated for this IRP, PacifiCorp also conducted a portfolio scenario study using the CEM and PaR models where a generator-based greenhouse gas emissions performance standard, such as the one in place in California, is instituted in all of PacifiCorp's service territory. The purpose of the study was to determine the comparative stochastic cost, risk, and CO_2 emission impacts of a portfolio that meets performance standard requirements as modeled using the CEM. This section first outlines the study approach and then presents comparative results with respect to the preferred portfolio (RA14) and the other Group 2 portfolios.

Scenario Study Approach

For this study, PacifiCorp first used the CEM to determine a deterministically optimized portfolio on the basis of GHG performance standard constraints, and then manually constrained the CEM resources to yield a portfolio with an improved cost and risk profile as determined by stochastic PaR model runs. This process is similar to the one used to develop the risk analysis portfolios.

The CEM was allowed to optimize resource selection and timing subject to assumptions designed to restrict resources to those that can comply with a CO_2 emission performance standard (a per-ton emissions amount comparable or less than a CCCT). The specific CEM portfolio assumptions for the study are as follows:

- Resources available for selection by the CEM include CCCT (F and G types with duct firing), IGCC with carbon capture and sequestration (CCS), renewables, DSM (both Class 1 and Class 3), and combined heat and power; pulverized coal was excluded as a resource option.
- No constraints were placed on resource amounts, timing, or location, except for earliest available in-service dates.
- A total of 3,700 megawatts of renewables was made available for selection.
- Renewable portfolio standards for California, Oregon, and Washington were assumed to be in place. The RPS requirements were handled as state contributions to a gross percentage on system retail loads—the same method used for previous RPS portfolio modeling. The percentages were updated based on the March 2007 load forecast.
- The quantity of front office transactions was limited to 1,200 megawatts after 2011 (700 in the east and 500 megawatts in the west).
- A 12 percent planning reserve margin and $8/ton CO_2 cost adder were assumed.

Table 7.49 shows the cumulative capacity by resource type and simulation period for the resulting CEM portfolio solution.

Table 7.49 – Capacity Additions for the Initial CEM GHG Emissions Performance Standard Portfolio

Resource	Cumulative Nameplate Capacity by Period (MW)	
	2007-2016	2007-2026
Gas - CCCT	1,507	6,410
Renewables	1,900	3,100
DSM	137	156
IGCC with CCS	-	-

As noted above, the CEM was not constrained to select certain resource amounts in certain years or areas. One consequence of this model set-up is that the resulting CEM portfolio does not reflect an investment schedule that is advantageous from a stochastic cost and risk standpoint. Another consequence is that the model's wind investment pattern differs significantly from what was identified in PacifiCorp's preferred portfolio. For example, the model did not recognize geographical RPS requirements in placing renewable resources; all wind resources were added in the east side until 2018. Additionally, the CEM included more renewables in 2007 than the preferred portfolio (700 megawatts versus 400 megawatts in the preferred portfolio), which is not practical from a procurement perspective.

To address these two issues, PacifiCorp first subjected this portfolio to stochastic simulation to create baseline stochastic results. Then, the CEM was executed again after applying resource constraints to the portfolio. These constraints include (1) limiting renewables to 300 megawatts in 2007[66], (2) adding an east-side CCCT in 2011 to replace a portion of front office transactions, and (3) fixing the east-side CCCT resource selected in 2011. The resulting CEM portfolio was simulated with the PaR model, and stochastic results compared against those of the original CEM portfolio. These resource constraints reduced stochastic mean PVRR by $144 million, risk exposure by $671 million, and upper-tail risk by $816 million. Table 7.50 shows the resource additions for the final GHG emission performance standard portfolio from 2007 through 2026. As with the other risk analysis portfolios, load growth and capacity reserve requirements are met with CCCT growth stations after 2018.

Stochastic Cost and Risk Results

Table 7.51 provides the stochastic cost and risk results for the GHG emission performance standard portfolio by CO_2 cost adder case. Results are shown for both the CO_2 tax and cap-and-trade compliance scenarios. Figures 7.37 through 7.39 show the cost-versus-risk trade-off of the portfolio in relation to the other Group 2 risk analysis portfolios assuming the CO_2 cap-and-trade scenario. Figure 7.37 is a scatter plot of the cost and risk measures based on the average of the five CO_2 adder cases, while Figures 7.38 and 7.39 show the cost and risk results for the $0 and $61 CO_2 adder cases, respectively.

[66] The remainder of the renewables investment schedule was not altered in order to minimize manual portfolio changes.

Table 7.50 – Resource Investment Schedule for the Final GHG Emissions Performance Standard Portfolio

		Nameplate Capacity, MW																			
	Resource	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East	CCCT, 2 x 1 F Class	-	-	-	-	548	548	-	-	-	-	548	-	1,096	-	-	548	-	-	-	548
	Renewables, SE ID	200	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-
	Renewables, WY	100	700	-	200	-	100	-	-	200	-	-	-	-	-	-	-	-	-	-	-
	Renewables, NV	-	-	-	-	-	-	-	-	-	-	200	200	-	-	-	-	-	-	-	-
	DSM, Class 1 and 3	-	-	-	-	-	7	7	7	-	-	52	52	52	-	-	-	-	-	-	-
	Front office transactions	-	-	-	486	550	158	130	563	98	700	505	556	-	-	-	-	-	-	-	-
West	CCCT, 2 x 1 F Class	-	-	-	-	-	602	-	-	-	-	-	-	602	-	-	-	602	-	602	-
	CCCT, 1x1 G Class	-	-	-	-	-	-	-	-	-	-	392	-	-	-	-	-	-	-	-	-
	Renewables, SE WA	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-
	Renewables, MT	-	-	-	-	-	-	-	-	-	-	-	400	-	-	-	-	-	-	-	-
	Renewables, NC OR	-	-	-	-	-	-	100	-	-	-	-	300	-	-	-	-	-	-	-	-
	DSM, Class 1 and 3	-	-	-	-	-	3	3	3	-	-	19	19	20	-	-	-	-	-	-	-
	Front office transactions	-	-	-	69	311	400	500	250	250	416	250	250	-	-	-	-	-	-	-	-
	Total Annual Additions	300	700	-	755	1,409	1,818	740	823	1,048	1,316	2,167	1,778	1,770	-	-	548	602	-	602	548

Table 7.51 – Stochastic Cost and Risk Results for the Final GHG Emissions Performance Standard Portfolio

CO_2 Cost Adder Case (2008 $)	Stochastic Results (Million $) – CO_2 Tax Basis					
	Stochastic Mean PVRR	5th Percentile	95th Percentile	Upper-Tail Mean	Risk Exposure	Standard Deviation
$0	23,230	14,637	37,387	70,858	47,628	13,046
$8	26,950	16,244	42,547	78,253	51,303	14,152
$15	28,731	17,754	45,152	81,756	53,026	14,695
$38	34,956	21,172	54,802	95,420	60,465	17,063
$61	41,227	24,484	64,948	110,445	69,218	19,823
CO_2 Cost Adder Case (2008 $)	Stochastic Results (Million $) – CO_2 Cap and Trade Basis					
	Stochastic Mean PVRR	5th Percentile	95th Percentile	Upper-Tail Mean	Risk Exposure	Standard Deviation
$0	21,922	13,330	36,080	69,550	47,628	13,046
$8	22,033	11,327	37,630	73,336	51,303	14,152
$15	22,014	11,037	38,435	75,039	53,026	14,695
$38	21,470	7,687	41,316	81,935	60,465	17,063
$61	20,577	3,834	44,298	89,795	69,218	19,823

Figure 7.37 – Average Stochastic Cost versus Risk Exposure Across All CO_2 Adder Cases

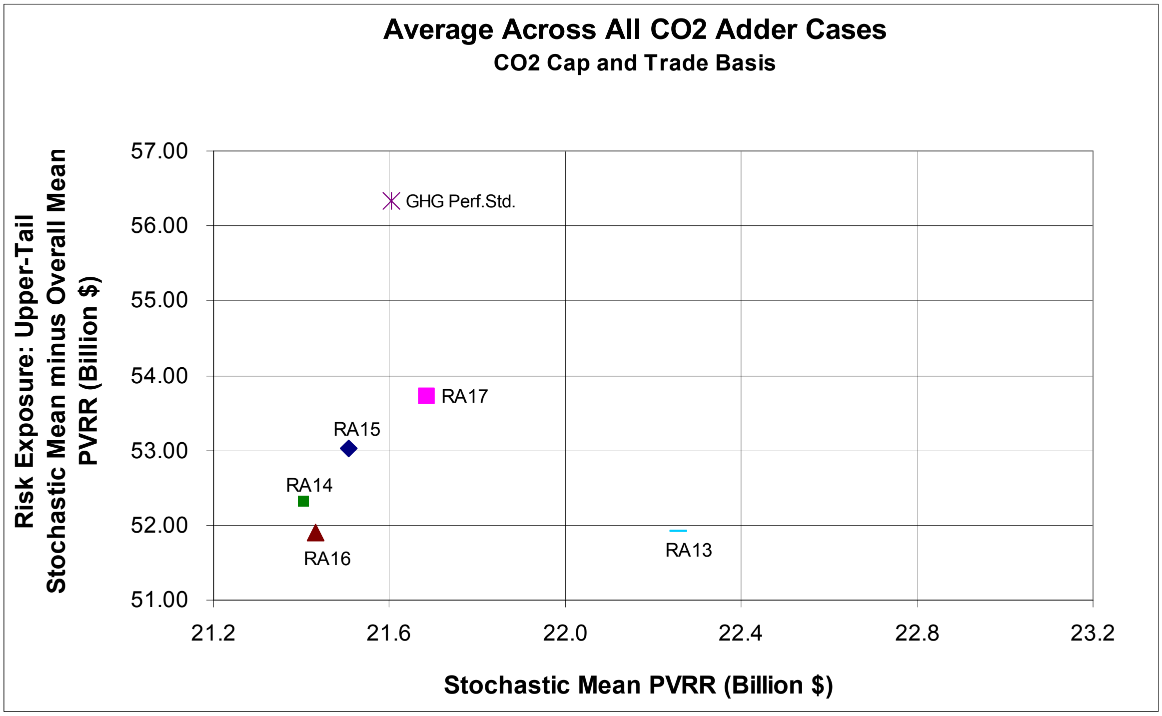


Figure 7.38 – Stochastic Cost versus Risk Exposure for the $0 CO_2 Adder Case

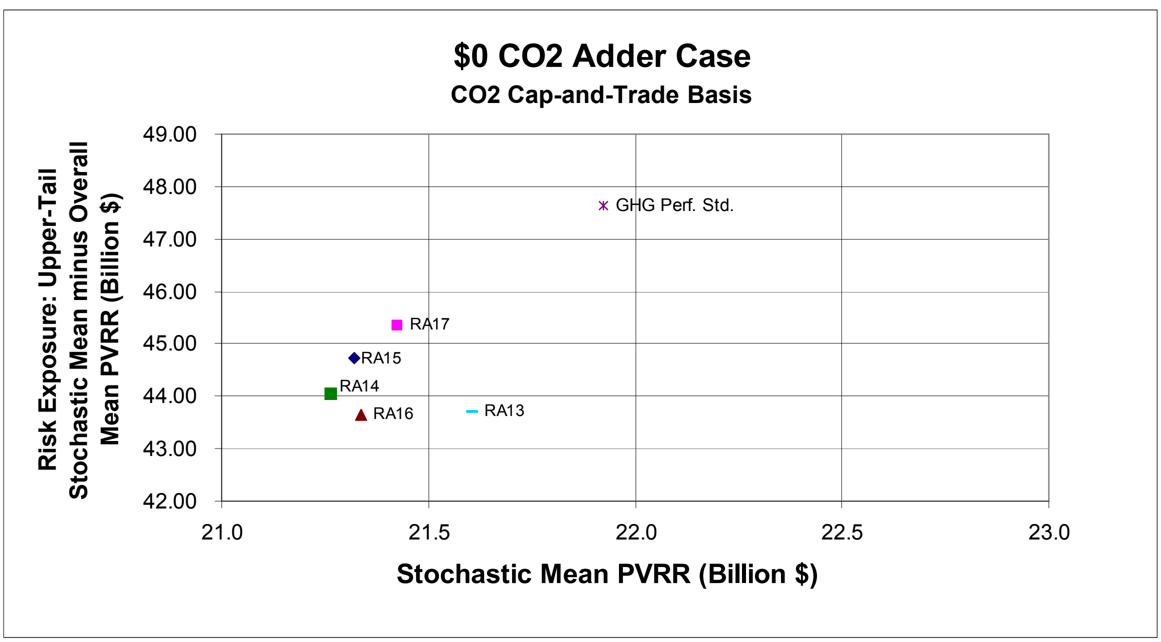
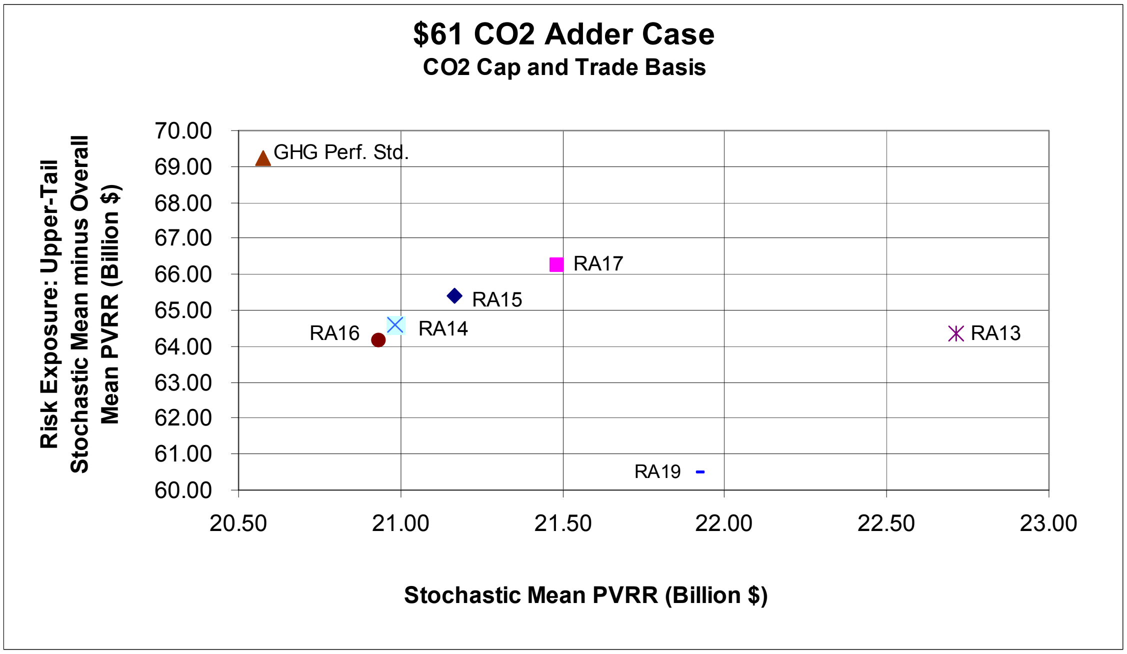


Figure 7.39 – Stochastic Cost versus Risk Exposure for the \$61 CO_2 Adder Case



As can be seen from the figures, the stochastic cost ranking of the GHG emissions performance standard portfolio relative to the Group 2 risk analysis portfolios is sensitive to the CO_2 cost adder level. Under the \$0/ton CO_2 adder case, the stochastic PVRR of the GHG emissions performance standard portfolio is \$662 million higher than that of the preferred portfolio. In contrast, under the \$61/ton CO_2 adder case, the preferred portfolio stochastic PVRR is \$406 million higher. When averaging stochastic PVRR results across the CO_2 adder cases, the GHG emissions performance standard portfolio falls within the middle of the pack.

The GHG emissions performance standard portfolio has the highest risk among the Group 2 portfolios for all CO_2 adder scenarios. In comparison to the preferred portfolio, risk is about \$3.6 billion higher under the \$0/ton CO_2 adder and \$4.6 billion higher under the \$61/ton CO_2 adder.

Carbon Dioxide Emissions Results

As expected, the GHG emissions performance standard portfolio has a smaller CO_2 footprint than the other risk analysis portfolios due to the lack of new coal plants. Relative to the preferred portfolio, the GHG emissions performance standard portfolio emits about 49 million fewer tons of CO_2 on a cumulative basis from 2007 through 2026 when averaged across the five CO_2 adder cases.

The annual CO_2 emissions impact of the adder can be seen by comparing Figures 7.40 and 7.41, which show emissions under the \$0 and \$61/ton CO_2 adders, respectively. (Annual emission quantities are reported as the contribution from retail sales; that is, net of wholesale sales.) Figure 7.42 shows annual CO_2 emission trends as the average of the results for the six portfolios.

Figure 7.40 – Annual CO_2 Emission Trends, 2007-2026 ($0 CO_2 Adder Case)

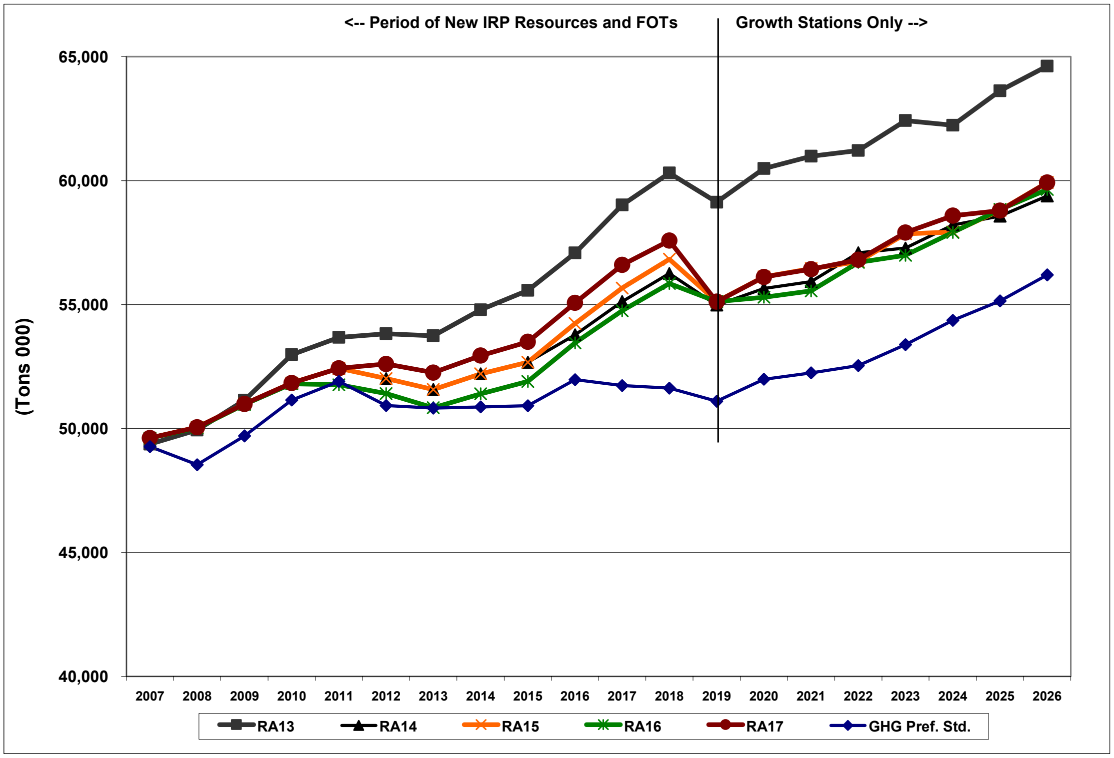


Figure 7.41 – Annual CO_2 Emission Trends, 2007-2026 ($61 CO_2 Adder Case)

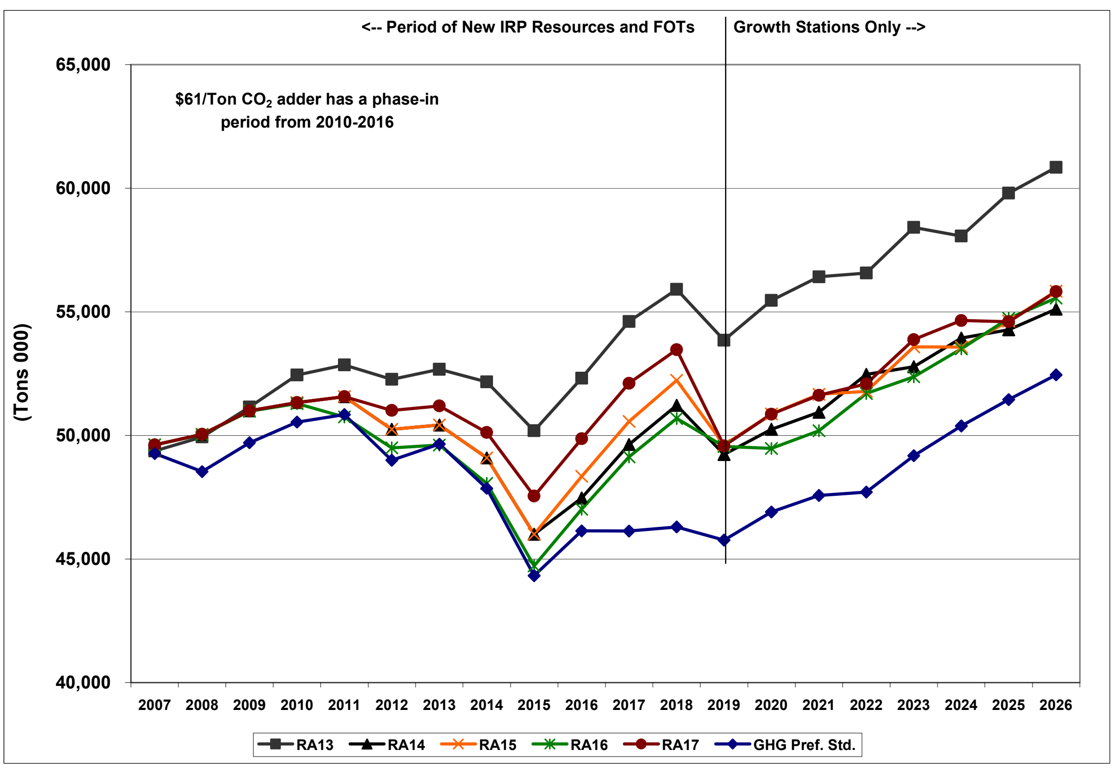
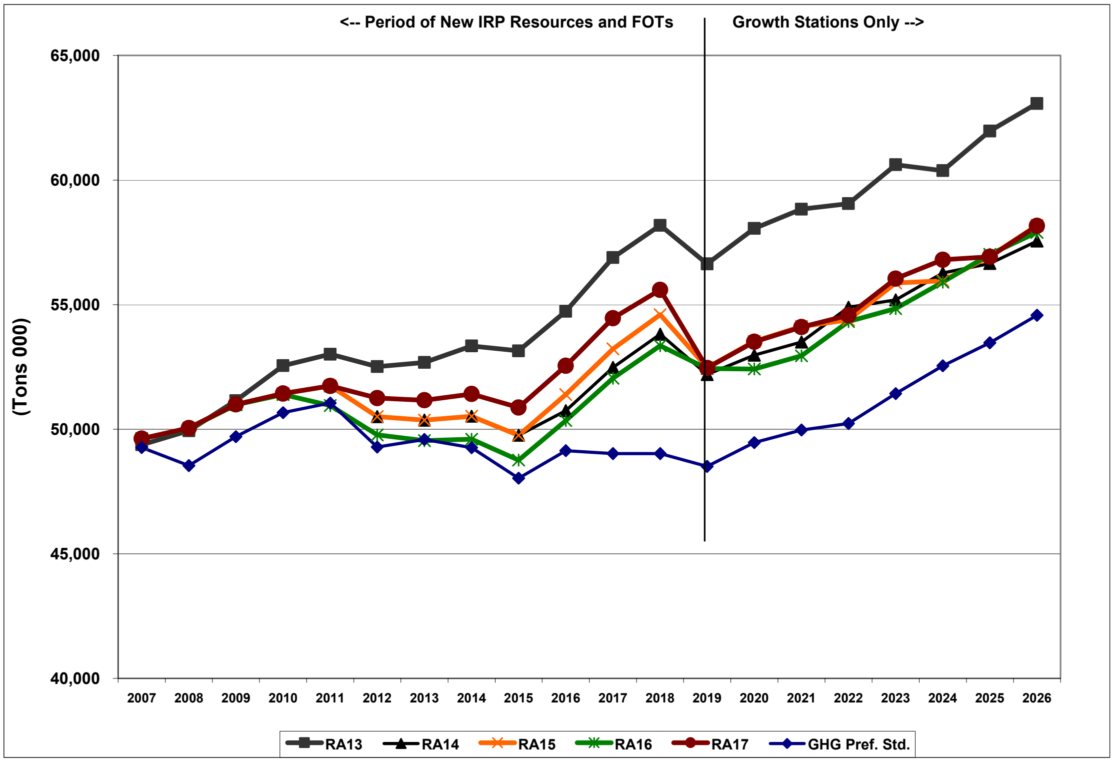


Figure 7.42 – Annual CO_2 Emission Trends, 2007-2026 (Average for all CO_2 Adder Cases)



8. ACTION PLAN

Chapter Highlights

- The company plans to accelerate its previous commitment to acquire 1,400 megawatts of cost-effective renewable resources from 2015 to 2010, and increase this amount to 2,000 megawatts of cost-effective renewable resources by 2013.
- The company will seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources since it is expected that wind will comprise a large portion of the company's accelerated and expanded renewable portfolio.
- The company will continue to run programs to acquire 250 average megawatts of cost-effective energy efficiency, and an additional 200 average megawatts if cost-effective initiatives can be identified.
- The company plans to maintain and build upon the existing 150 megawatts of irrigation and air conditioning load control in Utah and Idaho, and add 100 megawatts of additional irrigation load control split between system-East and system-West beginning in 2010.
- The company will seek to leverage voluntary demand-side measures, such as demand buyback, to improve system reliability during peak load hours.
- The company plans to acquire up to 1,700 megawatts of base load resources on the east side of its system for the term 2012 through 2014, consistent with the filed request for proposal.
- The company plans to acquire 200 to 1,300 megawatts of base load resource on the west side of its system in 2010 to 2014 through a mix of thermal resources and purchases.
- The company plans to expand its transmission system to allow the resources identified in the preferred portfolio to serve customer loads in a cost-effective and reliable manner.
- The company will incorporate the results of the demand-side management potential study into its business and into future integrated resource plans.
- The company will continue to take a leadership role in discussions on global climate change and will continue to investigate carbon reduction technology, including nuclear power.
- The company plans to enhance its integrated resource planning modeling to better address emerging issues on renewable portfolio standards and carbon regulation.
- The company will continue to work with stakeholders on cost allocation issues in order to achieve a portfolio that meets each state's energy policy.

INTRODUCTION

This chapter presents the company's 2007 action plan, which identifies the steps the company will take during the next two years to implement this plan. It is based on the guidance provided by the company's analysis and results described in Chapters 1 through 7 of this document as well as feedback from stakeholders. In large part, the action plan is used to map out the steps required to acquire the resources identified in the preferred portfolio and to identify ways to improve the company's future integrated resource planning.

To develop the action plan, the company used the preferred portfolio as shown in Table 8.1 (Portfolio RA14) along with issues raised by stakeholders during the course of the 2007 integrated resource planning process.

Table 8.1 – Resource Investment Schedule for Portfolio RA14

Supply and Demand-side Proxy Resources			Nameplate Capacity, MW									
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combined cycle CT	2x1 F class with duct firing						548				
	Combined cycle CT	1x1 G class with duct firing										357
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	393	272	97	3	149	192	165
West	CCCT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Load control, Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	-	219	64	555	657	247	246	249
	Annual Additions, Long Term Resources		300	300	100	312	839	1,125	318	527	-	357
	Annual Additions, Short Term Resources		-	-	-	612	336	652	660	396	438	414
	Total Annual Additions		300	300	100	924	1,175	1,777	978	923	438	771

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

Transmission Proxy Resources*		Transfer Capability, Megawatts									
	Resource	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Path C Upgrade: Borah to Path-C South to Utah North				300						
	Utah - Desert Southwest (Includes Mona - Oquirrh)						600				
	Mona - Utah North						400				
	Craig-Hayden to Park City						176				
	Miners - Jim Bridger - Terminal						600				
	Jim Bridger - Terminal								500		
West	Walla Walla - Yakima				400						
	West Main - Walla Walla					630					
	Total Annual Additions	-	-	-	700	630	1,776	-	500	-	-

* Transmission resource proxies represent a range of possible procurement strategies, including new wheeling contracts or construction of transmission facilities by PacifiCorp or as a joint project with other parties.

THE INTEGRATED RESOURCE PLAN ACTION PLAN

The IRP action plan, detailed in Table 8.2, provides the company with a road map for moving forward with new resource acquisitions over the next two years. The IRP action plan is based upon the latest and most accurate information available at the time the integrated resource plan is filed. The resources identified in the plan are proxy resources and act as a guide to resource procurement. As resources are acquired, the resource type, timing, size, and location may vary from the proxy resource identified in the plan. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition.

Table 8.2 – 2007 IRP Action Plan

Action Item	Category	Action Type	Calendar-Year Timing	Size (rounded to the nearest 50 MW for generation resources)	Location	IRP Proxy Resource Modeled	Action
1	Renewables	New Renewables	2007 - 2013	2,000	System	Wind	Acquire 2,000 MW of renewables by 2013, including the 1,400 MW outlined in the Renewable Plan. Seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources.
2	DSM	Existing and New Class 2 programs	2007 - 2014	450 MWa	System	100 MW decrements at various load shapes	Use decrement values to assess cost-effectiveness of new program proposals. Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and up to an additional 200 MWa if cost-effective initiatives can be identified. Will reassess Class 2 objectives upon completion of system-wide DSM potential study to be completed by June 2007. Will incorporate potentials study findings into the 2007 update and 2008 integrated resource planning processes.
3	DSM	New Class 1 programs	2007 - 2014	100	East - 50 West - 50	East and West irrigation load control, East summer loads	Targets were established through potential study work performed for the 2007 IRP. A new potential study is expected to be completed by June 2007, and associated findings will be incorporated into the 2007 update and the 2008 integrated resource planning processes.

Action Item	**Category**	**Action Type**	**Calendar-Year Timing**	**Size** (rounded to the nearest 50 MW for generation resources)	**Location**	**IRP Proxy Resource Modeled**	**Action**
4	DSM	Existing and New Class 3 programs	2007 - 2014	To be determined	System	Class 3: demand buy-back, hourly pricing, seasonal pricing, etc. Class 4: system messaging and education	Although not currently in the base resource stack, the company will seek to leverage Class 3 and 4 resources to improve system reliability during peak load hours. Will incorporate potential study findings into the 2007 update and/or 2008 integrated resource planning processes.
5	Distributed Generation	Combined Heat and Power (CHP)	2007-2014	100	System	25 MW steam topping cycle CHP; 5 MW gas combustion turbine CHP	Pursue at least 75 MW of CHP generation for the west-side and 25 MW for the east-side, to include purchase of CHP output pursuant to PURPA regulations and from supply-side RFP outcomes. The potential study results will be incorporated into the 2007 update and 2008 integrated resource planning processes
6	Distributed Generation	Standby Generators	2007-2014	To be determined	System	60 MW of diesel engine capacity on the west side	Will incorporate potential study findings into the 2007 update and 2008 integrated resource planning processes
7	Supply-Side	Base Load / Intermediate Load	2012	550	East	CCCT (Wet "F" 2X1) with duct firing	Procure a base load / intermediate load resource in the east by the summer of 2012. This is part of the requirement included in the Base Load RFP
8	Supply-Side	Base Load / Intermediate Load	2012	350	East	Supercritical pulverized coal (340 MW Utah unit)	Procure a base load / intermediate load resource in the east by the summer of 2012. This is part of the requirement included in the Base Load RFP
9	Supply-Side	Base Load / Intermediate Load	2014	550	East	Supercritical pulverized coal (527 MW Wyoming unit)	Procure a base load / intermediate load resource in the east by the summer of 2014. This is part of the requirement included in the Base Load RFP

Action Item	Category	Action Type	Calendar-Year Timing	Size (rounded to the nearest 50 MW for generation resources)	Location	IRP Proxy Resource Modeled	Action
10	Supply-Side	Base Load / Intermediate Load	2016	350	East	CCCT (Wet "G" 1X1) with duct firing	Investigate a base load / intermediate load resource in the east by the summer of 2016. This is not part of the requirement included in the Base Load RFP
11	Supply-Side	Base Load / Intermediate Load	2011	600	West	CCCT (Wet “F” 2X1) with duct firing	Procure a base load / intermediate load resource in the west by the summer of 2011 - 2012
12	Supply-Side	Base Load / Intermediate Load	2010-2014	350-650	East / West	Front office transactions: West - flat annual products East - 3rd quarter products	Procure base load / intermediate load resource beginning in the summer of 2010, use the Base Load RFP as appropriate to fill the need in the east
13	Transmission	Transmission	2010 and beyond	Various	System	Path C Upgrade Utah - Desert Southwest Mona - Utah North Craig Hayden - Utah North Miners - Utah North Jim Bridger - Utah North Walla Walla - Yakima Walla Walla - West Main	Pursue the addition of transmission facilities or wheeling contracts as identified in the IRP to cost-effectively meet retail load requirements, integrate wind and provide system reliability. Work with other transmission providers to facilitate joint projects where appropriate
14	Climate Change	Strategy and Policy	Ongoing	Not applicable	System	Not applicable	Continue to have dialogue with stakeholders on Global Climate Change issues
15	Carbon-Reducing Technology	Strategy and Policy	Ongoing	Not applicable	System	Not applicable	Evaluate technologies that can reduce the carbon dioxide emissions of the company's resource portfolio in a cost-effective manner, including but not limited to, clean coal, sequestration, and nuclear power

Action Item	Category	Action Type	Calendar-Year Timing	**Size** (rounded to the nearest 50 MW for generation resources)	Location	IRP Proxy Resource Modeled	Action
16	IRP Planning	Modeling and Analysis	2007-2008	Not applicable	System	Not applicable	Continue to investigate implications of integrating at least 2,000 MW of wind to PacifiCorp's system
17	IRP Planning	Modeling and Analysis	2007-2008	Not applicable	System	Not applicable	Update modeling tools and assumptions to reflect policy changes in the area of renewable portfolio standards and carbon dioxide emissions
18	IRP Acknowledgement	Policy and cost recovery	2007	Not applicable	System	Not applicable	Work with states to gain acknowledgement or acceptance of the 2007 integrated resource plan and action plan. To the extent state policies result in different acknowledged plans, work with states to achieve state policy goals in a manner that results in full cost recovery of prudently incurred costs

RESOURCE PROCUREMENT

Overall Resource Procurement Strategy

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

For demand-side resources, PacifiCorp uses a variety of business processes to implement DSM programs. The outsourcing model is preferred where the supplier takes the performance risk for achieving DSM results (such as the Cool Keeper program). In other cases, PacifiCorp project manages the program and contracts out specific tasks (such as the Energy FinAnswer program). A third method is to operate the program completely in-house as was done with the Idaho Irrigation Load Control program. The business process used for any given program is based on operational expertise, performance risk and cost-effectiveness. As with supply-side resources, the company may resort to competitive bidding with an RFP process to uncover new program opportunities.

Renewable Resources

The 2007 integrated resource plan identifies 2,000 megawatts of renewable resources to be acquired by 2013. Under this plan, the company seeks to acquire 1,400 megawatts of new renewable resources by 2010, with an additional 600 megawatts in place by 2013. The 2,000 megawatts of renewable resources is inclusive of the 1,400 megawatts of cost-effective renewable resources identified in the company's renewable plan. In order to fill this requirement, the company will continue to aggressively pursue the acquisition of these resources through various approaches including new requests for proposals, bi-lateral negotiations, the Public Utilities Regulatory Policy Act, and self-development. While the company used wind for modeling purposes in the integrated resource planning process, renewable generation includes other fuel sources such as biomass and landfill gas. In addition, the company will actively seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources and work to continuously improve its understanding of how to integrate large amounts of wind into its portfolio in a reliable and cost-effective manner.

Demand-side Management

The company has a variety of ongoing programs and associations to procure energy efficiency measures (Class 2 demand-side resources) from industrial, commercial and residential customers. These programs will be leveraged, and company-offered programs extended to other states, as the means to acquire the majority of the 250 average megawatts of Class 2 demand-side resources identified in the 2007 integrated resource plan. The company will continue these programs as long as they are cost-effective, and will seek to add new cost-effective programs in order to meet this target. The company will also continue to pursue an additional 200 average megawatts of energy efficiency measures if cost-effective.

With regard to load control (Class 1 demand-side resources), the company is actively working to retain the existing customers and continue expanding participation in these programs to achieve and build upon the 150 megawatts currently identified in the 2007 plan as an existing resource. The company will pursue acquisition of an additional 100 megawatts of load control identified in the preferred portfolio starting in 2010.

The company plans to leverage voluntary load control programs (Class 3 demand-side resources) such as demand buyback, hourly pricing and seasonal pricing, as well as system messaging and education (Class 4 demand-side resources), to improve system reliability during peak load hours.

Finally, the company will be completing a demand-side management potential study in June 2007, which will provide updated information on the potential for acquiring cost-effective demand-side resources across all major resource types (load management, energy efficiency, demand response and system messaging and education). Information learned from the demand-side management potential study will be incorporated in the company's demand-side management programs and in future integrated resource plans.

Combined Heat and Power

The 2007 integrated resource plan includes 100 megawatts of new combined heat and power in 2012. Combined heat and power facilities are allowed to bid into the company's current east side base load request for proposal, and can become part of the company's resource portfolio as qualifying facilities under the Public Utilities Regulatory Policy Act. Additional information on the potential for combined heat and power will be available from the demand-side management potential study and will be incorporated into the company's future integrated resource plans.

Distributed Generation

The company investigated the potential of adding distributed generation on the east side of its system and was informed by the Utah Department of Air Quality that it was not feasible to rely on existing standby generators at customer sites due to air quality considerations. On the west side of the system, the company found using sensitivity analysis that replacing a new resource with combined heat and power and aggregated dispatchable customer-owned standby generators marginally increased cost and risk. The company will have additional information on distributed generation potential as part of the demand-side management potential study. Based on this information, the company will determine what further steps to take with regard to distributed generation.

Thermal Base Load/Intermediate Load Resources

The company has an outstanding request for proposals that is aimed at acquiring up to 1,700 megawatts of cost-effective base load resource by 2014 on the east side of its system. The 2007 integrated resource plan identifies 1,450 megawatts of base load / intermediate load thermal resources needed on the east side of the system during this time frame based on a 12 percent planning reserve margin. Another 357 megawatts of base load / intermediate resource are identified in 2016. The 2007 integrated resource plan fully supports the outstanding Base Load Request for Proposal.

The 2007 integrated resource plan identified the need for 677 megawatts of base load / intermediate load thermal resources for the west side. The thermal resources consist of a 602 megawatt combined cycle natural gas plant in 2011 and 75 megawatts of combined heat and power in 2012. These proxy resources identified in the integrated resource plan will be used to guide the procurement of resources for the west side of the system such that the company can meet its deficit in the 2011-to-2012 time frame in a manner that is cost-effective, adjusted for risk. The actual mix and quantity of resources procured by the company to satisfy this need in the west may differ from the proxy resources identified in the integrated resource plan. Consistent with state guidelines for resource procurement, the company will perform updated analyses at the time new resources are acquired.

Front Office Transactions

The 2007 integrated resource plan identified the annual need for 50 to 650 megawatts of front office transactions on the west side of its system for 2010 to 2014. The front office transactions are modeled as flat annual purchases[67] and serve as a proxy for base load / intermediate load resources. Acquisition of front office transactions in the west will be considered in the context of the overall base load / intermediate load resource need in the west.

On the east side, the integrated resource plan identified the annual need for up to 400 megawatts of front office transactions for the 2010-to-2014 period. The need may be addressed using the Base Load Request for Proposals. Beyond this time frame, the annual need drops to no more than 200 megawatts.

Transmission Expansion

The 2007 integrated resource plan has identified a need for additional transmission as part of the preferred portfolio. In general, transmission additions reflect the need to meet retail load requirements, integrate wind and provide system reliability. Specific enhancements are required to integrate both the Wyoming and southern Utah areas with the Wasatch front, create additional integration with markets in the desert southwest, and integrate new resources and front office transactions with loads on the west side of the company's system.

The transmission additions identified in the preferred portfolio are proxy transmission additions. They are included as options that can be selected by the company's integrated resource planning models on a comparable basis with supply-side and demand-side resources. The proxy transmission additions included in the preferred portfolio serve as a guide to the company's transmission planners and may ultimately result in construction of new facilities by the company, partnering in regional transmission projects with others, or the execution of third party wheeling contracts. The timing and size of new transmission facilities may vary from the proxy transmission addi-

[67] Market purchases are assumed to be delivered at market hubs, primarily Mid-Columbia, and not at the load. For front office transactions to reach load, additional transmission is required.

tions included in the preferred portfolio due to specific siting, permitting and construction issues associated with a given project.

OTHER ISSUES

Global Climate Change

As discussed elsewhere in this IRP, one of the most challenging resource planning issues facing the company is how to address risk associated with the regulation of greenhouse gas emissions. As new climate policies and laws are adopted by state legislatures, utility commissions or the federal government to limit the utilization of higher carbon-emitting resources, PacifiCorp will adjust its capacity expansion model to account for those new policies.

To address this challenge, PacifiCorp has formed a Global Climate Change Working Group to analyze and discuss utility best practices in managing emissions of greenhouse gases and identify cost-effective opportunities to reduce greenhouse gas emissions within the respective states' regulatory framework. The company expects to have filed, with all six commissions, a preliminary Global Climate Change Action Plan by the fourth quarter 2007.

PacifiCorp employees will continue to have dialogue with stakeholders on this issue, explaining the various efforts already underway, and with stakeholder partners offering guidance and feedback on how the company might improve upon the efforts identified within the Global Climate Change Action Plan.

Separately, PacifiCorp is engaged in several partnerships, such as the Big Sky Carbon Sequestration Partnership and the Electric Power Research Institute, to explore energy, climate change, economic growth and carbon sequestration opportunities. The company also continues to participate in groups organized at state government levels that are designed to develop global climate change policy such as Oregon Docket UM 1302 that is investigating the treatment of carbon dioxide risk in integrated resource planning.

Carbon Reducing Technologies

Since the second quarter of 2006, the company has sponsored a workgroup to specifically investigate integrated gasification combined cycle technology and carbon dioxide sequestration. As the company moves forward, it will expand its view to all feasible technologies that can potentially reduce carbon dioxide emissions in a cost-effective manner, including nuclear power. For example, the Wyoming Infrastructure Authority and PacifiCorp are pursuing joint project development activities for an IGCC facility in Wyoming.

Modeling Improvements

While the 2007 integrated resource plan addresses renewable portfolio standards and carbon risk, it is becoming increasingly important to refine the modeling capabilities in this area. The company will pursue enhancements to the integrated resource planning models to potentially incorporate more sophisticated methods to address new resource portfolio standards and carbon regulations.

Cost Assignment and Recovery

The preferred portfolio is based on the premise of a single integrated system with rolled-in costs for new resources as prescribed under the Revised Protocol allocation methodology. Acknowledgement or acceptance of a single plan is a prerequisite for use of the Revised Protocol when the company is acquiring new resources. To the extent states acknowledge or accept different plans, the company will work with the states to find ways to deliver different plans to different states, while maintaining the highest possible level of system integration benefits and assuring full cost recovery of prudently incurred costs required to serve retail customers.

ASSESSMENT OF OWNING ASSETS VERSUS PURCHASING POWER

As the company acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, the company would be in a better position to control costs, make life extension improvements, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at cost as long as the it remains economic. In addition, by owning a plant, the company can hedge itself from the uncertainty of relying on purchasing power from others. On the negative side, owning a facility subjects the company and customers to the risk that the cost of ownership and operation exceeds expectations, the cost of poor performance or early termination, fuel price risk, and the liability of reclamation at the end of the facilities life.

Purchasing power from another party can help mitigate the risk of cost overruns during construction and operation of the plant, can provide certainty of cost and performance, and can avoid any liabilities associated with closure of the plant. Short-term purchased power contracts could allow the company to forgo a long term decision for a period of time if it was deemed appropriate to do so. On the negative side, a purchase power contract could terminate prior to the end of the term, requiring the company to replace the output of the contract at then current market prices. In addition, the company and customers do not receive any of the savings that result from management of the asset, nor do they receive any of the value that arise from the plant after the contract has expired.

RESOURCE ACQUISITION PLAN PATH ANALYSIS

The Utah Public Service Commission's IRP standards and guidelines require that PacifiCorp's IRP contain 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."

PacifiCorp's resource acquisition path analysis plan for this IRP consists of the use of the IRP models for the Base Load Request For Proposals issued on April 5, 2007. The modeling plan entails evaluating bid resources on a portfolio basis similar to how portfolios were evaluated in the 2007 IRP. The timing of the RFP, with a consequent refreshing of analysis inputs and inclusion of PacifiCorp's benchmark resources, represents a logical and efficient strategy to address this requirement.

To formulate and analyze different resource acquisition paths, the RFP modeling process includes two deterministic scenario analysis steps in which bid resources, including PacifiCorp benchmark resources, are evaluated with the Capacity Expansion Module under a range of scenario assumptions. The scenarios capture a combination of alternative electricity/gas prices, CO_2 cost adders, and planning reserve margins.

The first scenario analysis step involves running the CEM with the full set of short-listed bid resources to assist in screening the resources. The second scenario analysis step occurs after stochastic simulation has been used to select bid resource finalists. The portfolio of bid resource finalists is subjected to another round of CEM runs using the same scenario set applied to initially screen the bid resources. In contrast to the first scenario analysis step, the bid resources are fixed, and CEM use is limited to just determining the dispatch solution and PVRR under different economic conditions. This path analysis step is intended to help assure the company that the bid resource finalists are robust with respect to cost and cost variability under alternative economic and planning assumptions.

Assuring a **bright future** for our customers

2007

Integrated Resource Plan

Appendices

PACIFICORP

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This 2007 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP 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 IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Left to Right):
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Hydroelectric Generation: Yale Reservoir (Washington)
Demand side management: Agricultural Irrigation
Thermal-Gas: Currant Creek Power Plant
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APPENDIX A – BASE ASSUMPTIONS

This appendix will cover the base assumptions used for both the Capacity Expansion Module and the Planning and Risk model used for portfolio analysis in the 2007 Integrated Resource Plan.

GENERAL ASSUMPTIONS

Study Period

PacifiCorp currently uses a calendar year that begins on January 1 and ends December 31. The study period covers a 20-year period beginning January 1, 2007 through December 31, 2026.

Inflation Curve

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 A.1 below). Unless otherwise stated, prices or values in this appendix are expressed in nominal dollars.

Table A.1 – Inflation

Calendar Years	Average Annual Rate (%)
2007-2013	1.86
2014-2020	1.80
2021-2026	1.88

Planning Reserve Margin

PacifiCorp assumed both 12 and 15 percent planning margin for developing the load and resource balance. Capacity Expansion Module scenario analysis used 12 percent as the low case, 15 percent as the medium case and 18 percent as a high case during the initial phase of analyses. To preserve planning flexibility, the company adopted a reserve margin range of 12 to 15 percent in recognition of uncertainties concerning the cost and reliability impact of evolving state resource policies to foster renewable energy development and reduce utilities' carbon footprints.

LOAD FORECAST

This load forecast section provides state-level forecasted retail sales summaries, load forecasting methodologies, and the elasticity studies. Chapter 4 provides the forecast information for each state and the system as a whole by year for 2007 through 2016.

State Summaries

Oregon

Table A.2 summarizes Oregon state forecasted sales growth compared with historical growth by customer class.

Table A.2 – Historical and Forecasted Sales Growth in Oregon

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	5,374	4,614	2,957	211	50	**13,207**
2006 GWh	5,554	4,843	3,238	237	41	**13,912**
Average Annual Growth Rate						
1995-05	1.2%	2.0%	-3.5%	-3.1%	5.0%	**0.1%**
2007-16	0.7%	1.5%	-0.9%	0.0%	0.9%	**0.6%**

The forecast of residential sales is expected to have a slightly slower growth than has been experienced historically. Population growth is expected to continue in the service area, which is driving some of the growth, while usage per customer in the residential class is expected to decline slightly due to conservation.

Forecasted commercial class sales are projected to grow slightly more slowly over the forecast horizon compared to historical periods. Usage per customer is projected to remain flat due to increased equipment efficiency which offsets increased saturation of air conditioning.

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

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

Washington

Table A.3 summarizes Washington state forecasted sales growth compared with historical growth by customer class.

Table A.3 – Historical and Forecasted Sales Growth in Washington

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	1,587	1,417	1,054	175	11	**4,244**
2006 GWh	1,596	1,415	990	155	10	**4,166**
Average Annual Growth Rate						
1995-05	1.1%	2.1%	0.8%	3.1%	2.9%	**1.4%**
2007-16	1.1%	1.2%	2.0%	0.0%	0.1%	**1.3%**

The growth in residential class sales is due to continuing population growth and household formation in this part of PacifiCorp's service area. Usage per customer is expected to increase slightly due to increases in both real income and the residential square footage.

The continuing residential customer growth also affects the commercial sector through increasing numbers of commercial customers. Usage per commercial customer is decreasing during the forecast horizon due to increasing saturations in air-conditioning and office equipment that are being offset by efficiency gains in other end-uses, such as lighting.

The industrial class is projected to grow at rates above the historical rate. Industrial production is projected to continue to grow in the food, lumber, and paper industries in the state. There are indications that bio-diesel facilities will locate in the state during the forecast period.

California

Table A.4 summarizes California state forecasted sales growth compared with historical growth by customer class.

Table A.4 – Historical and Forecasted Sales Growth in California

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	391	290	64	89	2	**837**
2006 GWh	398	293	62	96	2	**851**
Average Annual Growth Rate						
1995-05	1.0%	2.4%	-2.0%	2.0%	0.4%	**1.3%**
2007-16	0.9%	1.8%	-0.4%	0.0%	0.1%	**1.1%**

The rate of growth in residential class sales is driven, in part, by the continuing growth in population in this part of PacifiCorp's service area. Usage per customer in the residential class is declining slightly. Home sizes continue to increase, resulting in more growth in use per customer but this is more than offset by the increasing adoption of efficient appliances. In addition, summer electrical usage increases from air conditioning additions are being somewhat offset by declining electric spacing heating saturations and appliance efficiency gains.

The continuing population growth also affects sales in the commercial sector through continued commercial customer growth. Additionally, commercial usage per customer is increasing due to greater square footage per building in new construction, increases in the number of offices, and the increasing use of office equipment in all commercial structures. However, some of this growth is being offset from increased equipment efficiency over the forecast horizon.

Declines over the decade in the lumber and wood product industries production resulted in an overall decline in the industrial sales; however, there are indications that this trend has ended and growth in other businesses are expected to continue.

Utah

Table A.5 summarizes Utah state forecasted sales growth compared with historical growth by customer class.

Table A.5 – Historical and Forecasted Sales Growth in Utah

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	5,707	6,776	6,944	151	547	**20,124**
2006 GWh	6,139	7,079	7,312	171	525	**21,227**

	Residential	Commercial	Industrial	Irrigation	Other	Total
Average Annual Growth Rate						
1995-05	4.2%	5.0%	0.9%	2.9%	0.3%	**3.0%**
2007-16	3.4%	3.3%	1.7%	0.7%	0.3%	**2.7%**

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

The relatively high population growth also affects sales in the commercial sector by continued commercial customer growth. Usage per customer is projected to increase with new construction having greater square footage per building and increasing usage of office equipment. However, some of this growth is being offset from equipment efficiency gains over the forecast horizon.

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

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

Idaho

Table A.6 summarizes Idaho state forecasted sales growth compared with historical growth by customer class.

Table A.6 – Historical and Forecasted Sales Growth in Idaho

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	652	382	1,650	534	2	**3,221**
2006 GWh	678	401	1,659	592	2	**3,332**
Average Annual Growth Rate						
1995-05	1.7%	5.6%	-0.0%	2.5%	3.2%	**1.3%**
2007-16	2.2%	3.1%	0.0%	0.6%	1.2%	**1.0%**

The growth of sales in the residential sales class continues to be strong in the forecast horizon due to customer growth and increased usage per customer. The customer growth is driven by strong net in-migration and household formation. The increased usage per customer is driven by

larger home size and a relatively large number of people per household. It is also assumed that air conditioning saturation rates will continue to be increasing during the forecast horizon.
The growth rate for commercial class sales is expected to be less than historic levels but will continue to be strong due to customer growth in response to the increasing residential customer growth and due to an increase in the number of offices. Usage per customer is projected to increase, which has been influenced in part by new construction at the Brigham Young University Idaho campus, increased air conditioning saturation, office equipment, and exterior lighting. However, this growth is somewhat offset by equipment efficiency gains over the forecast horizon.

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

Wyoming
Table A.7 summarizes Wyoming state forecasted sales growth compared with historical growth by customer class.

Table A.7 – Historical and Forecasted Sales Growth in Wyoming

	Residential	Commercial	Industrial	Irrigation	Other	Total
2005 GWh	939	1,290	5,756	16	13	**8,013**
2006 GWh	970	1,367	5,939	21	13	**8,309**
Average Annual Growth Rate						
1995-05	1.4%	2.5%	1.2%	4.1%	0.1%	**1.4%**
2007-16	1.6%	2.6%	6.7%	-0.5%	0.2%	**5.6%**

The residential sales forecast is expected to continue to grow at nearly historical rates. Population growth is expected to continue in the service area, which causes some of the growth. Home sizes continue to increase, resulting in increased general use per customer. Increasing air conditioning saturations are resulting in more use per customer during the summer months.

Commercial sales are projected to grow at a similar rate over the forecast horizon compared to historical periods due to customer growth and increasing usage per customer. Customer growth occurs in response to residential customer growth and the growth of the office sector. Usage per customer is projected to increase for the forecast period due to increases of office and miscellaneous equipment.

A major change in the Wyoming sales forecast occurs in the industrial sales sector. Large gas extraction customers are expected to locate in the PacifiCorp service area. The location of these industrial customers in the service area also contributes to the growth in the residential and commercial customer sectors.

<u>Class 2 DSM</u>

Identified and budgeted Class 2 DSM programs have been included in the load forecast as a decrement to the load. By 2016, there are 143 MWa of Class 2 programs in the forecast. This savings includes 10 MWa to be implemented by the Energy Trust of Oregon within PacifiCorp's service territory. Table A.8 shows average program savings and peak obligation hour savings by year. In 2016, these Class 2 programs reduce peak system load from what it otherwise would have been by 2.2%.

Table A.8 – Class 2 DSM Included in the System Load Forecast

MWa	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
PacifiCorp	19	38	54	62	75	87	100	112	124	135
Energy Trust of Oregon (ETO)	11	20	27	36	45	54	63	73	82	92
TOTAL	**30**	**58**	**81**	**98**	**120**	**141**	**163**	**185**	**206**	**227**
Peak Reduction (MW)	**40**	**77**	**108**	**131**	**160**	**188**	**217**	**247**	**275**	**303**

<u>Near Term Customer Class Sales Forecast Methods</u>

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:

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

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

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

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

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, which are 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 of the six states served by PacifiCorp. 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.[1]

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 a region’s share of the employment for these specific industries based on national forecasts of employment for the industries.

The non-basic sector theoretically represents those businesses whose output serves the local market and whose market demand 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.

Residential Sector

For the first time PacifiCorp implemented the end-use software package Residential End-Use Energy Planning System (REEPS) to produce the long-term residential sales forecast. This residential end-use forecasting model has been developed to forecast specific uses of electricity in the customer’s home. 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 energy usage is projected on the basis of 14 end-uses. These uses are space heating, water heating, electric ranges, dishwashers, electric dryers, first refrigerators, second refrigerators, lighting, air conditioning, freezers, microwave ovens, electric clothes washers, color televisions 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. 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

[1] 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.

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, such as air conditioning, the saturation rate has been adjusted to account for this occurrence. For other appliances, such as 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.

Consumption= Housing Stock $_{k}$, X Saturation of Appliance $_{ik}$ X 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.

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

REEPS allows 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
For the first time PacifiCorp implemented the end-use software package Commercial End-Use Energy Planning System (COMMEND) to produce the long-term commercial sales forecast. It forecasts electricity in the same fashion as the REEPS model but uses energy use per square foot for ten end-uses among ten commercial building types.

Consumption= Square foot $_{k}$, X Saturation of Appliance $_{ik}$ X Electricity Usage of Appliance $_{ik}$

where: i = Appliance Type
k = Commercial Activity Type

The nine end-uses are space heating, water heating, space cooling, ventilation, refrigeration, interior lighting, exterior lighting, cooking, office equipment and miscellaneous uses.

Ten building types are modeled: offices, restaurants, retail, grocery stores, warehouses, colleges, schools, health, lodging, and miscellaneous buildings. Individual forecasts for each building type 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 ten categories based on the Standard Industrial Classification code system. These are: food processing (SIC 20), lumber and wood products (SIC 24), paper and allied products (SIC 26), chemicals and allied products (SIC 28), petroleum refining (SIC 29), stone, clay and glass (SIC 32), primary metals (SIC 33), electrical machinery (SIC 36) and transportation equipment (SIC 37). A residual manufacturing category, composed of all remaining manufacturing SIC codes, is also forecasted.

The mining industry, located primarily in Wyoming and Utah, has been disaggregated into at least four categories. Separate forecast 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.

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 which converges these values to the long-term forecast.

Total Load Forecasting 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 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 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 determined.

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, the model uses hourly temperatures for weather stations where the bulk of the load in the state resides. 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 industrial and some commercial customers use less electricity. Therefore, a variable used to identify a weekend would have a lower contribution to the forecasted load than a weekday variable; using the calendar date for a future period 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 made to ensure that the loads are growing at the appropriate times. State loads are aggregated by month and by time of day, and future growth rates are compared with historical growth rates. This allows PacifiCorp to review the nighttime 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 totaled across the months of the forecast period to develop monthly loads. 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.

Treatment of State Economic Development Policies
The load forecast for each state depends to some degree on the state economic forecast provided by Global Insights. The state economic forecast from Global Insights is dependent on a series of econometric equations based on historical values of state and national economic variables. To the extent that a state has had economic development policies in the past, it is reflected to a similar degree in the state economic forecast and, thus, impacts the load forecast. Periodically, Global Insights will include in the state economic forecast newly developed state economic policies judgmentally external to the econometric forecasting equations when it is deemed appropriate to

include such programs in the forecast. Since it is assumed that the economic forecast includes all existing and relevant new economic development programs, the load forecast includes the impacts of these programs.

<u>Elasticity Studies</u>

Since the 2004 IRP, PacifiCorp has performed three separate studies on the effects of the price of electricity on electricity usage in Utah. Each study evaluates the increasing block rates of the residential customer class. That is, the increasing price of electricity during the summer should cause a decline in the usage of electricity, especially during times of peak demand in Utah.

These three studies can be classified as
1) Total residential class analysis through econometric methods
2) Analysis, using econometric methods, of customers who called about their electric bills, and
3) Sub-group analysis of the residential class using cluster analysis and econometric analysis

Total Class Analysis
An econometric equation with usage per customer as the dependent variable and the real price of electricity, real household income, cooling degree days[2], heating degree days, real natural gas prices, and lagged use per customer as independent variables was developed. The time period of estimation was from 1982 through 2005. The results of this estimation indicate that the short-term price elasticity was -0.05 and that the long-term price elasticity was -0.09. Using either measure, it was determined that electricity is price inelastic, i.e., having an elasticity measure less than 1 in absolute value, or relatively unresponsive to changes in the price of electricity. In particular, the short-term elasticity measure indicates that for a 10 percent increase in price there is a 0.5 percent decline in the usage of electricity one year in the future. The long-term measure indicates that a 10 percent increase in the price of electricity ultimately leads to a 0.9 percent decline in electricity usage.

Analysis of Customers Who Called About Their Bills
During 2004 PacifiCorp received calls from 77 customers in Utah who indicated that they were calling about price issues. Of these 77 customers 13 had sufficient data to analyze their usage in response to price changes. An econometric equation was specified having the log of average monthly kilowatt-hours (kWh) as the dependent variable and the log of average real price current and lagged one month, the log of average usage per month lagged on month, heating degree days, and cooling degree days as independent variables.

The results of this econometric analysis indicated that the price variables were not statistically significant, which implies that the price coefficient and elasticity is statistically equal to zero. This result means that among those who notified PacifiCorp about changes in their price of electricity, there was no measurable change in their usage.

[2] All heating and cooling degree day variables in these analyses were based on temperature data from the Salt Lake City Airport.

Sub-group Analysis
The sub-group analysis used cluster analysis to group customer in accordance with their usage patterns over the last six years. To be included in the analysis, a customer had to be receiving service since July 1999 and the minimum amount of monthly usage was restricted to 55 kilowatt-hours.

The number of residential customers satisfying both conditions was 136,042. From this group of customers, the customers were clustered in accordance to their usage monthly usage patterns and amounts since July 1999. Using traditional cluster analysis techniques based on changes in monthly usage patterns and amounts, it was found that there were 23 clusters of 500 or more customers, with the final cluster being all other remaining customers. For these 24 groups of customers, regression analysis was performed with the dependent variable being the log of average monthly kilowatt-hours for the group and the independent variables being the log of the group average price per kilowatt-hours, the log of the group average price per kilowatt-hours and the log of the lagged average monthly kilowatt-hours, monthly heating degree days and monthly cooling degree days.

Of these 24 groups, two groups indicated a change in electricity usage in response to changes in the price of electricity. One group consisted of 1,490 customers with a summer average usage of 1,096 kilowatt-hours per month. This group had an elasticity measure of -2.51 which implies that a 10 percent increase in price would lead to a 25.1 percent decline in electricity usage for this group. The second group consisted of 505 customers with a summer average usage of 2,340 kilowatt-hours per month. This group had an elasticity measure of -0.95 which implies that a 10 percent increase in price would lead to a 9.5 percent decline in electricity usage for this group. These two groups represent roughly 2 percent of the 136,042 original customers. The remaining groups, which represented 98 percent of the customers, had no usage response to price changes. When weighing the groups according to their percent representation, the analysis implies that the total price elasticity is -0.036; i.e., electricity is price inelastic in total, which indicates that for the total residential class a 10 percent increase in price leads to a 0.36 percent decline in total residential usage.

COMMODITY PRICES

Market Fundamental Forecasts

PacifiCorp has historically relied on PIRA Energy's long range Reference Case forecast of natural gas prices as a primary input to its fundamental forward price curve. The PIRA forecast, translated to western delivery points, is used both to forecast electricity market prices in its fundamentals-based price forecasting model, Multi-objective Integrated Decision Analysis (MIDAS), and directly as fundamental forward price curves for natural gas.

PIRA Energy, through its Scenario Planning Service, also forecasts low and high scenarios for natural gas prices and estimates probabilities associated with these cases and the reference case. Prior to the August 2006 forward price curve, PacifiCorp did not use the low and high natural gas price scenarios in the development of its fundamental forward price curve, relying exclusively on the reference case.

Since 2003, when PIRA began its scenario planning service, natural gas prices and price forecasts have increased dramatically. A number of well documented supply and demand factors have contributed to this shift. In addition to a higher reference case, market changes have also led PIRA to forecast a wider range of low and high scenarios and higher probabilities associated with the high price scenarios.

In its August 2006 update to scenario forecasts, PIRA raised the probability associated with the high scenario from 25 to 30 percent and lowered the low scenario probability from 30 to 25 percent. PIRA documented these changes and the explanation for their forecast revisions in their quarterly update. The factors contributing to the shift include the following:

- Increasing probability of global liquefied natural gas (LNG) supply constraints and higher costs arising from slower expansion of liquefaction, escalation of project costs, rising global demand competition from emerging economies, higher political and supply disruption risks, and state gas companies' extraction of higher economic rents through royalties that have roughly doubled.
- Increasing risks to the timing and success of arctic frontier pipelines (Mackenzie Delta and Alaska North Slope).
- Mounting evidence of a more sensitive price elasticity of supply on the part of US producers who can rapidly step down exploration and production efforts in response to lower prices, especially in light of continuing high crude oil prices.

PIRA's ability to ascribe probabilities to their base, high and low cases will allow changes in any of the scenarios or probabilities associated with them to be reflected. PacifiCorp includes this improvement by probability-weighting PIRA's cases using PIRA's quarterly and annual updates to scenario forecasts. This method is an improvement over the company's historic use of the PIRA reference case forecast because it is responsive to increasing uncertainty surrounding future natural gas prices and also because it better reflects the current view of higher risk of higher natural gas prices in the future. Should the market outlook change and revert to one with more certainty and less high price risk, the probability weighted forecast will also capture that change.

PacifiCorp's official electricity price forecasts are a blend of market prices and output results from MIDAS.

Modeling Resource Additions in MIDAS

There are three general categories of resource additions added to the MIDAS price forecasting model: (1) renewable generation additions under renewable portfolio standard requirements or based on published integrated resource plans, (2) specifically identified new resource additions and (3) other capacity needed to meet load growth and planning reserve.

Multiple states in the Western Interconnection have adopted renewable portfolio standards. While renewable portfolio standards vary considerably by state, they all require affected entities to hit pre-specified renewable targets measured as a percentage of retail sales. If the mandated RPS targets in each state are to be met, various types of renewable resources must be added to the Western Interconnection resource supply over time.

Not all states and provinces within the Western Interconnection are subject to renewable portfolio standards. However, utilities within these regions have been including renewable generation in their integrated resource plans. The recent history of renewable additions confirms the likelihood of additions specified in integrated resource plans coming to fruition. MIDAS modeling includes this IRP-reflected trend of adding renewable resources in areas unaffected by renewable portfolio standard legislation in the Western Interconnection.

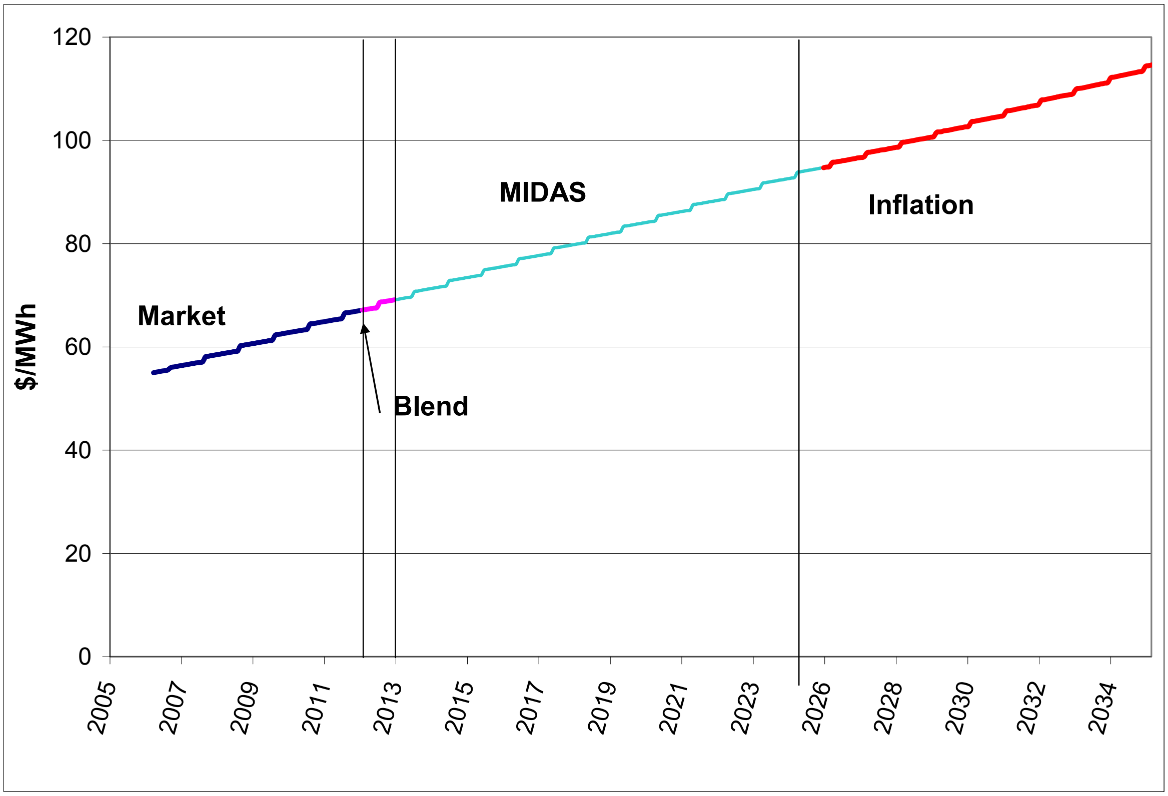
Total RPS-required and IRP-reflected renewable resource capacity additions added to MIDAS through 2025 is almost 20,000 GWh, which represents a mix of wind, geothermal, solar, biomass, landfill gas and small hydro projects.

New resource additions include specifically identified resource additions within the Western Interconnection and are only added to MIDAS after independent sources have verified that the units are under construction, operational or far enough into advanced development such that completion on-line date can be forecasted with confidence.

The MIDAS market resource expansion module adds new capacity in response to market prices or to meet load growth and planning reserves through its automated resource addition logic. Resources evaluated by MIDAS include natural gas simple cycle combustion turbines, intercooled aeroderivative simple cycles, and combined cycles (with and without duct firing); coal-fired units; and IGCC units. As regions express preferences for, or restrict the usage of, certain resource types (such as coal), the mix of resources that can be added by the model to meet load growth or planning reserves will change.

As Figure A.1 shows, market prices are used exclusively for the first 72 months. The official August 2006 prices reflected market prices on August 31, 2006. Market prices are derived from actual market transactions and broker quotes from polling the industry. Months 73-84 are the average of corresponding adjacent market and MIDAS prices (e.g. month 73 = (market month 61 + MIDAS month 85)/2). Starting in the 85th month and through 2025, prices from MIDAS are used exclusively. After 2025, prices are escalated using PacifiCorp's June 2006 inflation curve. The plot in Figure A.1 illustrates the blending period.

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



For Illustration Purposes Only

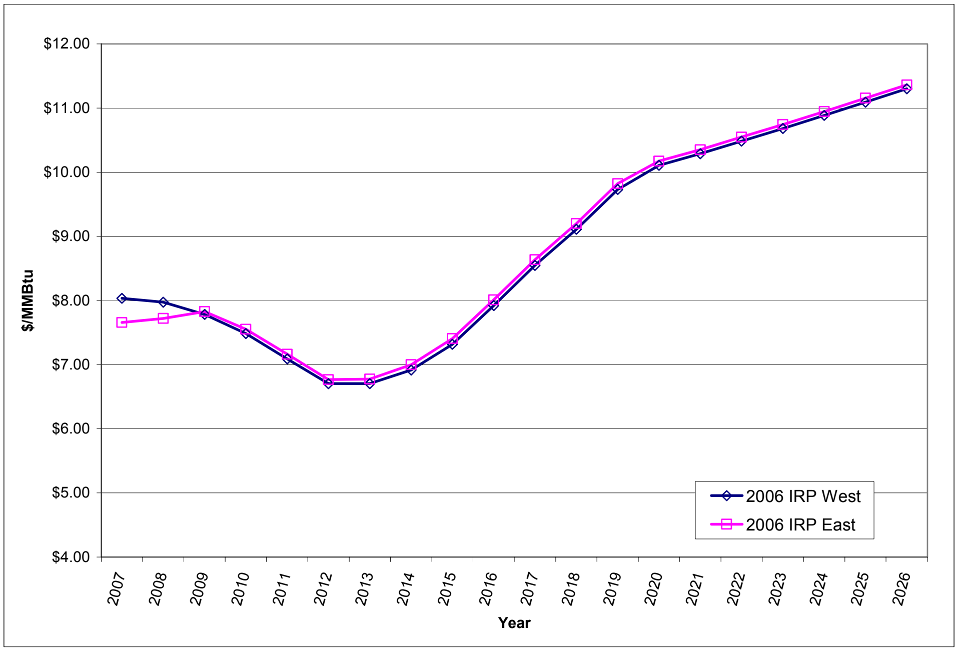
Gas Price Forecasts

As described in the Market Fundamental Forecast section, natural gas prices for the first six years are from the market on August 31, 2006 and for the next year are a blend of market prices and the gas prices used in MIDAS or PIRA. Starting in year seven, PIRA's natural gas price forecast is used exclusively.

Natural gas price assumptions in MIDAS are based on PIRA Energy's July 25, 2006 short-term forecast, the August 3, 2006 probabilistic weighted long-term gas forecast, and the August 22, 2006 long-term gas basis differentials. PIRA gas price projections are used in MIDAS through 2020. All prices are adjusted to be consistent with PacifiCorp's official inflation curve issued in June 2006. Gas prices beyond 2020 are escalated using PacifiCorp's inflation curve, which was updated on June 6, 2006.

IRP west side natural gas prices are an average of prices at the Sumas, Stanfield and Opal delivery points. Natural gas prices on the east side are based on the Opal delivery point prices. Figure A.2 shows the natural gas price forecasts used in the 2007 IRP.

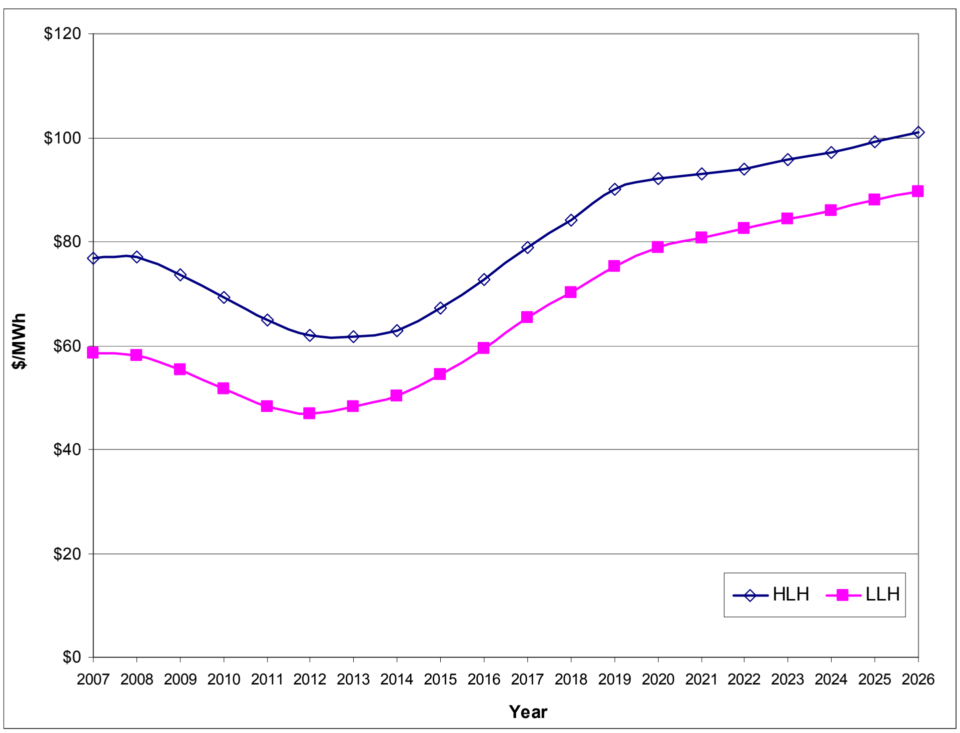
Figure A.2 – Natural Gas Price Curve



Wholesale Electricity Price Forecasts

Figure A.3 shows the annual average of heavy load hours (HLH) and light load hours (LLH) for wholesale electricity price forecasts dated August 31, 2006 that are used in the 2007 IRP.

Figure A.3 – Wholesale Electricity Price Forecast – Heavy Load Hours / Light Load Hours



Post-2020 real growth rate sensitivity analysis
At the May 10, 2005 public meeting, there was discussion about using real escalation for natural gas prices past 2020. PIRA provides natural gas prices through 2020 and PacifiCorp's official natural gas forecast beyond 2020 is escalated using PacifiCorp's inflation curve.

Another credible source, EIA Annual Energy Outlook February 2006, assumes gas escalation beyond 2020 to be approximately 1.5 percent in real terms.

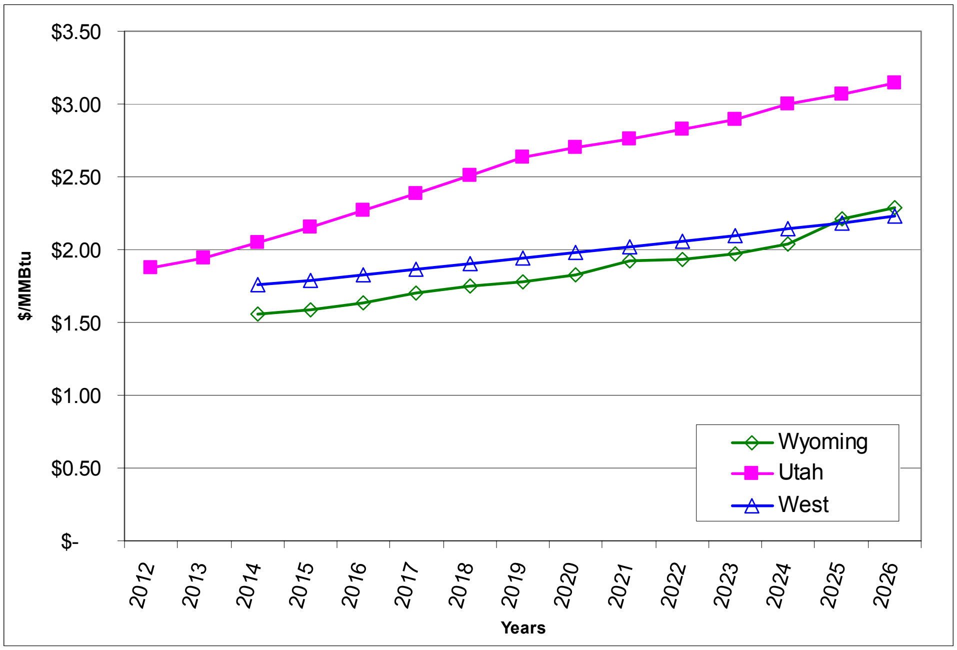
This level of natural gas real escalation was run through the MIDAS model and market prices increased on average by 1.8 percent for the period 2012 through 2025. This was felt to be such a small impact that it was not required to run these market prices through the CEM and PaR models.

Regional transmission project impact analysis
For the regional transmission sensitivity, new transmission lines were added to the MIDAS model topology to determine market price sensitivity. A new 1,500 megawatts line was added from Wyoming to SP15 and a new 1,150 megawatts line was added from Utah to NP15. These lines were sized to be consistent with the size of new coal plants that were added in Wyoming and Utah by the MIDAS automatic resource addition logic. The average market prices for the period 2012 through 2025 decreased on average by approximately -0.2 percent. Gas generation is on the margin and determines market prices, which are relatively unaffected by increased transmission.

Coal Prices

Figure A.4 reflects PacifiCorp's estimate of delivered coal costs for its western control area (West), 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.

Figure A.4 – Average Annual Coal Prices for Resource Additions



The current IRP plan only contemplates siting coal fired plants at PacifiCorp sites in the West, 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.

Coal Prices – West Side IGCC

The estimated delivered price of fuel delivered to west-side IGCC resources is $1.50/MMBtu in calendar-year 2006 dollars. Published values for a 50/50 blend of petroleum coke and Powder River Basin (PRB) coal from a publicly available document on one of the proposed IGCC projects is estimated at $1.35/MMBtu. The $1.50/MMBtu value reflects uncertainty in the eventual delivered fuel cost, and is considered conservative based on discussions with one party currently proposing an IGCC facility.

It is expected that west-side IGCC resources will be able to be fueled with a wide range of fuels with the predominant fuel being low-cost petroleum coke or a blend of petroleum coke and low-cost western fuels, such as PRB coal. Recently proposed IGCC projects in the Pacific Northwest (Energy Northwest's Pacific Mountain Energy Center and Summit Power Group's Lower Columbia Clean Energy Center) are located adjacent to deep water ports with rail access allowing for multiple kinds of fuel to be delivered, including petroleum coke, as well as western and international coals. The range of coals that could be used will depend primarily on the design characteristics of the gasifier, the fuel processing equipment, and the capabilities of the syn-gas clean up systems.

EMISSION COSTS

Carbon Dioxide

The CO_2 adder is based upon the possibility of mandated green house gas reductions across the U.S. electric generating sector. The CO_2 adder reflects the company's estimate of compliance costs set at $8/ton in 2008 dollars adjusted for inflation using PacifiCorp's official June 2006 inflation curve. To account for the uncertainty surrounding when such a cost will be imputed upon generating units, prices in 2010 and 2011 are probability weighted. The probability weighting applied to 2010 and 2011 prices are 0.5 and 0.75 respectively. By 2012, it is assumed that the CO_2 policy will be fully implemented. CO_2 prices are $4.15/ton in 2010, $6.34/ton in 2011 and $8.62/ton in 2012 and escalate at PacifiCorp's June 2006 inflation curve.

The portfolio modeling utilized alternative CO_2 cost adders for scenario analysis. These alternative cost adders, along with the $8/ton case, are shown in Table A.9.

Table A.9 – CO_2 cost adders used for Scenario Analysis

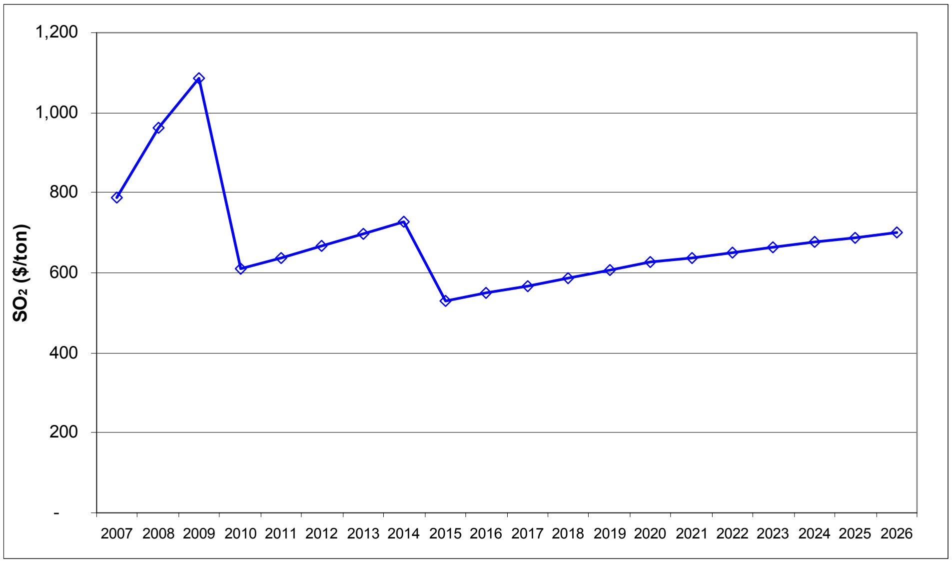
Year	CO_2 Cost Adder Levels ($/Ton, 2008 Dollars)				
	$0	$8	$15	$38	$61
2010	0.00	4.15	4.15	4.15	4.15
2011	0.00	6.34	6.34	6.34	6.34
2012	0.00	8.62	8.62	8.62	8.62
2013	0.00	8.78	8.78	8.78	8.78
2014	0.00	8.94	11.05	17.69	24.34
2015	0.00	9.10	13.89	35.63	67.43
2016	0.00	9.26	17.64	44.09	70.55
2017	0.00	9.43	17.97	44.90	71.85
2018	0.00	9.60	18.29	45.71	73.15
2019	0.00	9.77	18.62	46.53	74.45
2020	0.00	9.95	18.96	47.38	75.82
2021	0.00	10.13	19.30	48.24	77.19
2022	0.00	10.32	19.67	49.14	78.64
2023	0.00	10.52	20.05	50.10	80.16
2024	0.00	10.72	20.43	51.05	81.68
2025	0.00	10.92	20.81	52.00	83.20
2026	0.00	11.13	21.20	52.99	84.78

Sulfur Dioxide

The short-term SO_2 allowance price forecast reflects PIRA's May 30, 2006 forecast. The SO_2 price trajectory is based upon the May 2006 Emissions Market Intelligence Service report issued by PIRA with the following adjustments. The PIRA price forecast is provided in real dollars and is adjusted for inflation using PacifiCorp's official inflation forecast issued in June 2006 to produce a nominal spot price forecast. Prices beyond 2020 are grown using the same official inflation curve. New SO_2 allowance prices were adopted to align with a PIRA update and EPA's

Clean Air Interstate Rule (CAIR). CAIR requires 2 existing Acid Rain Program allowances for each ton of emissions beginning in 2010 and 2.86:1 in 2015. This surrender ratio applies to Eastern states, but does not apply in the West. Effectively, this lowers allowance prices by a factor of 2 in 2010 and 2.83 in 2015. Figure A.5 shows the SO_2 spot emission costs used in the 2007 IRP.

Figure A.5 – Sulfur-Dioxide (SO_2) Spot Price Forecast



Nitrogen Oxides

The NO_X price forecast reflects PacifiCorp's expectation that by 2012 some form of annual NO_X cap-and-trade program will be imposed in the West. Considering the West does not have the same ground-level ozone problems experienced in the East, the forecast assumes that the NO_X trading program imposed in 2012 will be less stringent than what is currently targeted under EPA's Clean Air Interstate Rule (CAIR) for Eastern states. As a result, the marginal control technology is assumed to be selective non-catalytic reduction (SNCR) as opposed to selective catalytic reduction (SCR). While it is by no means certain that a market-based allowance trading mechanism will be imposed eventually on western states NO_X emissions, this assumption serves as a reasonable proxy for additional control costs that are likely to arise from NO_X regulations driven by existing regulations. In 2012 NO_X allowance costs are expected to be $1,145/ton and escalate at PacifiCorp's June 2006 inflation curve.

Mercury

Mercury (Hg) prices reflect co-benefits from the installation of SO_2 and NO_X controls with a cap-and-trade program beginning in 2010. The mercury spot price forecast is based upon PIRA's Emissions Market Intelligence Service as of February 23, 2006. PIRA's forecast includes a range (high and low) for 2010, 2015, and 2020. Values between the years reported by PIRA are interpolated. All prices are adjusted to be consistent with PacifiCorp's official inflation curve issued in June 2006. Mercury prices are expected to be $7,197/Lb in 2010.

RENEWABLE 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 other resource technologies such as resources fueled by coal and natural gas. In the 2007 IRP, the tax credit is incorporated into the wind supply curves. Although the current law applies only to wind projects brought on-line through 2007, the effect on supply curves was extended throughout the study horizon for the purposes of the IRP analysis. It is widely expected that the PTC deadline will be extended, and will only end at such a time as the cost of the technology declines to the point where tax credits are no longer needed to keep wind competitive with other resource types. The 2007 IRP does not contain any specific expectation regarding declining wind resource costs due to technology improvements, using the assumption of an extended PTC to cover the combination of PTC and technology improvement effects.

Renewable Energy Credits

Renewable energy credits (RECs), also known as green tags, are certificates that represent the reporting rights for a quantity of energy generated from a specific resource. Markets have developed around buying and selling RECs. Consumers desiring to encourage renewable resources may purchase RECs, sometimes matching all or a portion of their electric power usage. Utilities may also purchase RECs to satisfy minimum renewable energy requirements established in some states.

Since PacifiCorp's 2003 IRP, a value has been ascribed to the green tags generated by owned renewable energy projects. That value was estimated to be $5 per megawatt-hour of generation for the first five years of production (constant nominal dollars). PacifiCorp called a number of green tag suppliers to ascertain whether the market value of RECs had substantially changed from where it has been over the past few years. Despite the expectation that increasing state minimum requirements for renewable generation would push market prices up, there was no clear indication that market prices had gone up. The potential market impacts of state standards was discussed, but the consensus was that the effect on market prices would be highly dependent on the specifics of state requirements, and did not clearly indicate a specific direction for green tag prices. In light of this, PacifiCorp has chosen to retain its REC value assumption of $5 per megawatt-hour for five years in constant nominal dollars.

EXISTING RESOURCES

Hydroelectric Generation

Table A.10 provides an operational profile for each of PacifiCorp's hydroelectric generation facilities. The dates listed refer to a calendar year.

Table A.10 – Hydroelectric Generation Facilities

Plant	PacifiCorp Share (MW)	Location	License Expiration Date	Retirement Date
West				
Big Fork	4.15	Montana	2001	2051
Clearwater 1	15.00	Oregon	1997	2040
Clearwater 2	26.00	Oregon	1997	2040
Copco 1	20.00	California	2006	2046
Copco 2	27.00	California	2006	2046
East Side	3.20	Oregon	2006	2016
Fish Creek	11.00	Oregon	1997	2040
Iron Gate	18.00	California	2006	2046
JC Boyle	80.00	Oregon	2006	2046
Lemolo 1	29.00	Oregon	1997	2040
Lemolo 2	33.00	Oregon	1997	2040
Merwin	136.00	Washington	2009	2046
Rogue	46.76	Oregon	Various	Various
Slide Creek	18.00	Oregon	1997	2040
Soda Springs	11.00	Oregon	1997	2040
Swift 1	240.00	Washington	2006	2046
Toketee	42.50	Oregon	1997	2040
West Side	0.60	Oregon	2006	2016
Yale	134.00	Washington	2001	2046
Small West Hydro	21.01	CA/OR/WA	Various	Various
East				
Bear River	114.50	ID/UT	Various	Various
Small East Hydro	26.50	ID/UT/WY	Various	Various

Hydroelectric Relicensing Impacts on Generation

Table A.11 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 imposed in new licenses will reduce generation available from these facilities.

Table A.11 – Estimated Impact of FERC License Renewals on Hydroelectric Generation

Year	Lost Generation (MWh)
2007	(154,370)
2008	(158,191)

Year	Lost Generation (MWh)
2009	(158,191)
2010	(158,191)
2011	(158,191)
2012	(168,035)
2013	(196,590)
2014	(196,590)
2015	(196,590)
2016	(212,383)
2017	(212,383)
2018	(212,383)
2019	(212,383)
2020	(212,383)
2021	(212,383)
2022	(212,383)
2023	(212,383)
2024	(212,383)
2025	(212,383)
2026	(212,383)

Note: Excludes the decommissioning of Condit, Cove, Powerdale, and American Fork.

Generation Resources

Table A.12 lists operational profile information for the PacifiCorp generation resources, including plant type, maximum megawatt capacity, ownership share, location, retirement date, and FERC Form 1 heat rates. Lake Side's heat rate has been approximated based on design expectations.

Table A.12 – Thermal and Renewable Generation Facilities

Plant	Maximum MW (PacifiCorp Share)	State	PacifiCorp Percentage Share	Retirement Date [1/]	Heat Rate (Btu/kWh)
Coal-fired					
Carbon 1	67	Utah	100%	2020	11,497
Carbon 2	105	Utah	100%	2020	11,497
Cholla 4	380	Arizona	100%	2025	10,815
Colstrip 3	74	Montana	10%	2029	10,870
Colstrip 4	74	Montana	10%	2029	10,870
Craig 1	83	Colorado	19%	2024	10,208
Craig 2	83	Colorado	19%	2024	10,208
Dave Johnston 1	106	Wyoming	100%	2020	11,047
Dave Johnston 2	106	Wyoming	100%	2020	11,047
Dave Johnston 3	220	Wyoming	100%	2020	11,047
Dave Johnston 4	330	Wyoming	100%	2020	11,047
Hayden 1	45	Colorado	24%	2024	10,571

Plant	Maximum MW (PacifiCorp Share)	State	PacifiCorp Percentage Share	Retirement Date [1/]	Heat Rate (Btu/kWh)
Hayden 2	33	Colorado	13%	2024	10,571
Hunter 1	403	Utah	94%	2031	10,508
Hunter 2	259	Utah	60%	2031	10,508
Hunter 3	460	Utah	100%	2031	10,508
Huntington 1	445	Utah	100%	2025	10,099
Huntington 2	450	Utah	100%	2025	10,099
Jim Bridger 1	353	Wyoming	67%	2026	10,569
Jim Bridger 2	353	Wyoming	67%	2026	10,569
Jim Bridger 3	353	Wyoming	67%	2026	10,569
Jim Bridger 4	353	Wyoming	67%	2026	10,569
Naughton 1	160	Wyoming	100%	2022	10,426
Naughton 2	210	Wyoming	100%	2022	10,426
Naughton 3	330	Wyoming	100%	2022	10,426
Wyodak 1	280	Wyoming	80%	2028	11,597
Gas-fired					
Currant Creek	541	Utah	100%	2040	7,327
Gadsby 1	60	Utah	100%	2017	11,590
Gadsby 2	75	Utah	100%	2017	11,590
Gadsby 3	100	Utah	100%	2017	11,590
Gadsby 4	40	Utah	100%	2027	11,556
Gadsby 5	40	Utah	100%	2027	11,556
Gadsby 6	40	Utah	100%	2027	11,556
Hermiston 1 [2/]	124	Oregon	50%	2031	7,222
Hermiston 2 [2/]	124	Oregon	50%	2031	7,222
Lake Side [3/]	544	Utah	100%	--	6,939
West Valley 1	40	Utah	100%	2008	10,694
West Valley 2	40	Utah	100%	2008	10,694
West Valley 3	40	Utah	100%	2008	10,694
West Valley 4	40	Utah	100%	2008	10,694
West Valley 5	40	Utah	100%	2008	10,694
Renewables and Other					
Blundell (Geothermal) [4/]	23	Utah	100%	2033	--
Foote Creek (Wind)	33	Wyoming	79%	2019	--
Leaning Juniper (Wind)	101	Oregon	100%	2031	--
James River (CHP)	30	Washington	100%	2016	7,200
Little Mountain (CHP)	14	Utah	100%	2009	16,980

1/ Plant lives are currently being reviewed for compliance with future environmental regulations.
2/ Remainder of Hermiston plant under purchase contract by the company for a total of 248 MW.
3/ Currently under construction; expected June 2007 start date.
4/ Planned Blundell bottoming-cycle upgrade of 11 MW in 2008.

Demand-Side Management

This section provides tabular statistics for PacifiCorp's Class 1, 2, 3 and 4 demand-side management programs. For more information on demand-side management programs, see the following:

- Chapter 4 describes each of the demand-side management program classes.
- Chapter 4 summarizes how each of the Classes of demand-side management resources was incorporated in the portfolio simulation and analysis process.

Class 1 Demand-Side Management

Table A.13 details the base case Class 1 demand-side management programs. Peak load reductions for 2007-2016 are shown by program within each state.

Table A.13 – Class 1 Demand-Side Management Programs

Demand-side management program	Description	Program Contribution (Megawatts)	Availability
Irrigation Load Control	Incentive program for Idaho irrigation customers to participate in pumping load control program during the irrigation season.	50 megawatts in 2007 continuing for 10 years.	ID
Residential and Small Commercial Air Conditioner 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. This program may be expanded in size or expanded into other jurisdictions within this planning period.	90 megawatts by 2007 contracted for through 2013.	UT
Irrigation Load Control	Incentive program for Utah irrigation customers to participate in pumping load control program during the irrigation season	12 megawatts in 2007 continuing for 10 years.	UT

Note: The company discontinued Utah's commercial lighting load control program in August of 2006 following the program's inability to reach its targeted curtailment milestones.

Class 2 Demand-Side Management

Since the 2004 IRP, more current Class 2 data has been incorporated into the 2007 IRP Class 2 DSM in the system load forecast. Adjustments, which increased savings, include the proposed implementation of Wyoming programs and the introduction of the Home Energy savers program for residential customers in Idaho, Washington and Utah in 2006 and proposed for California and Wyoming in 2007. The Energy Trust of Oregon has completed another resource assessment which reduces their expected contributions from their programs over the planning period. Changing federal standards have reduced air conditioning savings available from the Utah Cool Cash program as well as have impacted other program forecasts. The Utah Load Lightener program, which was expected to contribute energy efficiency results in addition to load management opportunities, was removed to reflect cancellation of the program in early 2006. Business customer programs have been adjusted to reflect the decrease in savings associated with short payback work drying up and the increased time to acquire the higher complexity savings.

Table A.14 defines the Class 2 programs. Table A.15 provides base case Class 2 demand-side management program savings for calendar years 2007-2016.

Table A.14 – Class 2 Demand-Side Management programs

Demand-side Management Program	Description
Energy FinAnswer (incentive program)	Engineering and incentive package for improved energy efficiency in new construction and comprehensive retrofit projects in commercial, industrial and irrigation sectors. Incentives are based on $/kilowatt hour and $/kilowatt reductions.
Energy FinAnswer (loan program)	Engineering and financing package for improved energy efficiency in new construction and retrofit projects in the commercial, industrial and irrigation sectors.
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.
Recommissioning	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	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. Depending on the state, incentives for system re-design and replacements are offered or the project is referred to the Energy FinAnswer program.
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 are 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 environmentally and cost-effectively remove inefficient refrigerators and freezers 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. Program may incorporate energy education depending on the state.
Home Energy Savers Program	A broad based residential program offering customer incentives for the purchase of energy efficient lighting, equipment, appliances, insulation and energy efficient practices e.g. air conditioner tune-ups or duct sealing. The program measures may vary between states due to measure specific programs available in some states e.g. Utah's air conditioning efficiency program, "Cool Cash".
Energy Education	Program provides 6th graders with energy efficiency curriculum and home energy audit kits that include instant savings measures i.e. compact florescent lights, showerheads, temperature check cards, etc. This program is currently only available in Washington.

Demand-side Management Program	Description
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 Oregon, Washington, Idaho and Montana. 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 paid by Oregon customers. The non-governmental delivery agent under contract with the Oregon Public Utility Commission was created in March of 2002 as part of the state's electric industry restructuring legislation, Senate Bill 1149.

Table A.15 – Class 2 Demand-Side Management Service Area Totals – All States, All Programs

(Calculated at the generator)

PacifiCorp – Class 2 Service Area Total				
Calendar Year	MWa First Year	MWh First Year	MWa Cumulative	MWh Cumulative
2007	29.17	256,517	29.17	255,517
2008	28.22	247,197	57.12	500,399
2009	24.49	214,558	80.80	707,775
2010	23.66	207,254	97.85	857,169
2011	22.88	200,416	119.33	1,045,329
2012	22.63	198,214	140.87	1,234,039
2013	22.58	197,844	163.12	1,428,948
2014	21.68	189,932	184.80	1,618,835
2015	21.15	185,259	205.94	1,804,051
2016	20.81	182,305	226.75	1,986,311

PacifiCorp – Class 2 Program Totals				
Calendar Year	MWa First Year	MWh First Year	MWa Cumulative	MWh Cumulative
2007	18.67	164,537	18.67	163,537
2008	19.22	168,357	37.62	329,579
2009	16.89	147,982	53.70	470,379
2010	14.86	130,166	61.95	542,685
2011	14.08	123,328	74.63	653,757
2012	13.63	119,374	87.17	763,627
2013	13.08	114,624	99.92	875,316
2014	12.18	106,712	112.10	981,983
2015	11.65	102,039	123.74	1,083,979
2016	11.31	99,085	135.05	1,183,019

Energy Trust of Oregon Total				
Calendar Year	MWa First Year	MWh First Year	MWa Cumulative	MWh Cumulative
2007	10.50	91,980	10.50	91,980
2008	9.00	78,840	19.50	170,820
2009	7.60	66,576	27.10	237,396
2010	8.80	77,088	35.90	314,484
2011	8.80	77,088	44.70	391,572
2012	9.00	78,840	53.70	470,412
2013	9.50	83,220	63.20	553,632
2014	9.50	83,220	72.70	636,852
2015	9.50	83,220	82.20	720,072
2016	9.50	83,220	91.70	803,292

Class 3 Demand-Side Management

Table A.16 defines the company's Class 3 programs. Class 3 programs are treated as reliability resources and are not included within the company's base resources.

Table A.16 – Class 3 Demand-Side Management Programs

Demand-Side Management Class 3 Program	Description
Energy Exchange program	Web based notification program that allows participating customers to voluntarily reduce their electric usage in exchange for a payment at times and at prices determined by the company. The program is available to customers with loads equal to or greater than 1 megawatt as measured anytime within the last 12 months. The company is considering program revisions that among other program design changes may expand the program to customers with loads of less than 1 megawatt.
Oregon Time of Use program	Senate Bill 1149 portfolio offering for residential plus greater than 30 kilowatt commercial and irrigation customers. Program enables customers to potentially reduce their energy costs by shifting the bulk of their energy usage to off-peak periods year-round.
Oregon Critical Peak Pricing pilot	Still under development as of the writing of this report, the company has agreed to a critical peak pricing pilot in Oregon fashioned after California's investor owned utilities state-wide pricing pilot program. The program will likely be offered to residential and small commercial customers and be run for a two year period as the company collects information on the customer acceptance, behavioral performance, and cost-effectiveness of a larger offering.
Idaho Time of Day program – business and farm load customers	A program available to general service customers (non-residential, non-irrigation, non-street lighting and non-area lighting) with a maximum power requirement of 15,000 kilowatts or less. It encourages off-peak usage though tariff pricing.
Idaho Time of Day program – residential customers	A program available to residential customers (120 or 240 volt service with a single kilowatt hour meter). It encourages off-peak usage though tariff pricing.

Demand-Side Management Class 3 Program	Description
Utah Time of Day program – residential customers	A pilot program (1,000 customers) available to residential customers (120 or 240 volt service with a single kilowatt hour meter). It encourages off-peak usage though tariff pricing.
Interruptible contracts	The company has interruptible service agreements with a few major special contract customers that allow for service interruption during periods of system resource inadequacies and in some cases during periods of high market prices (economic dispatch).

Class 4 Demand-Side Management

Table A.17 defines the company's Class 4 programs. Class 4 program resources are naturally taken into consideration through the development of the company's integrated resource planning load forecasts.

Table A.17 – Class 4 Demand-Side Management Programs

Demand-Side Management Class 4 program	Description
"Do the bright thing" energy efficiency awareness and education advertising	General advertising messages that focus on low to no cost efficiency and load management tips and information encouraging customers to "Do the bright thing". Campaign activity increases during seasonal peak periods utilizing radio, newspaper, buses, customer newsletters, and other media channels. The umbrella tag line is utilized by some of our Class 2 program vendors in their advertising efforts and the general advertising often directs customers to available incentive programs to assist them in their energy efficient pursuits.
PowerForward program	A state of Utah program supported by company and other state utilities that issues public service announcements in a stop light manner to alert customers of critical peak usage situations and requests customers to curtail non-essential loads during yellow and red alerts.
Residential do-it-yourself audit	Web accessible do-it-yourself paper audit designed to assist customers in identifying how they use energy today and providing them economically based recommendations on how to improve the energy efficiency of their homes. Customers can fill-out the audit online or mail in a copy of the completed audit. The company will complete the audit analysis and mail customers their results.
Oregon residential web audit	Web based do-it-yourself audit designed to assist customers in identifying how they use energy today and providing them economically based recommendations on how to improve the energy efficiency of their homes. The program is funded by the Oregon's public purpose fund monies and operated by the Energy Trust of Oregon. A link to the program is found on the Pacific Power website.
Wyoming residential and small commercial energy advisor website.	Web based conservation advisor and energy advisor programs designed to assist customers in identifying how they use energy today and providing them economically based recommendations on how to improve the energy efficiency of their homes. The program is offered by the Wyoming Energy Conservation Network through a grant that was supported by PacifiCorp. A link to the program is found on the Rocky Mountain Power website.
Energy Education	Although this program is classified as a Class 2 resource due to its energy saving kit and associated savings, the program revolves around energy education, which is a Class 4 attribute. The program provides 6th graders with energy efficiency curriculum and home energy audit kits that include instant savings measures i.e. compact florescent lights, showerheads, temperature check cards, etc. This program is currently only available in Washington.

Transmission System

Topology

PacifiCorp uses a transmission topology consisting of 15 bubbles (geographical areas) in the East and nine bubbles in the West 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 A.6 shows the IRP transmission topology.

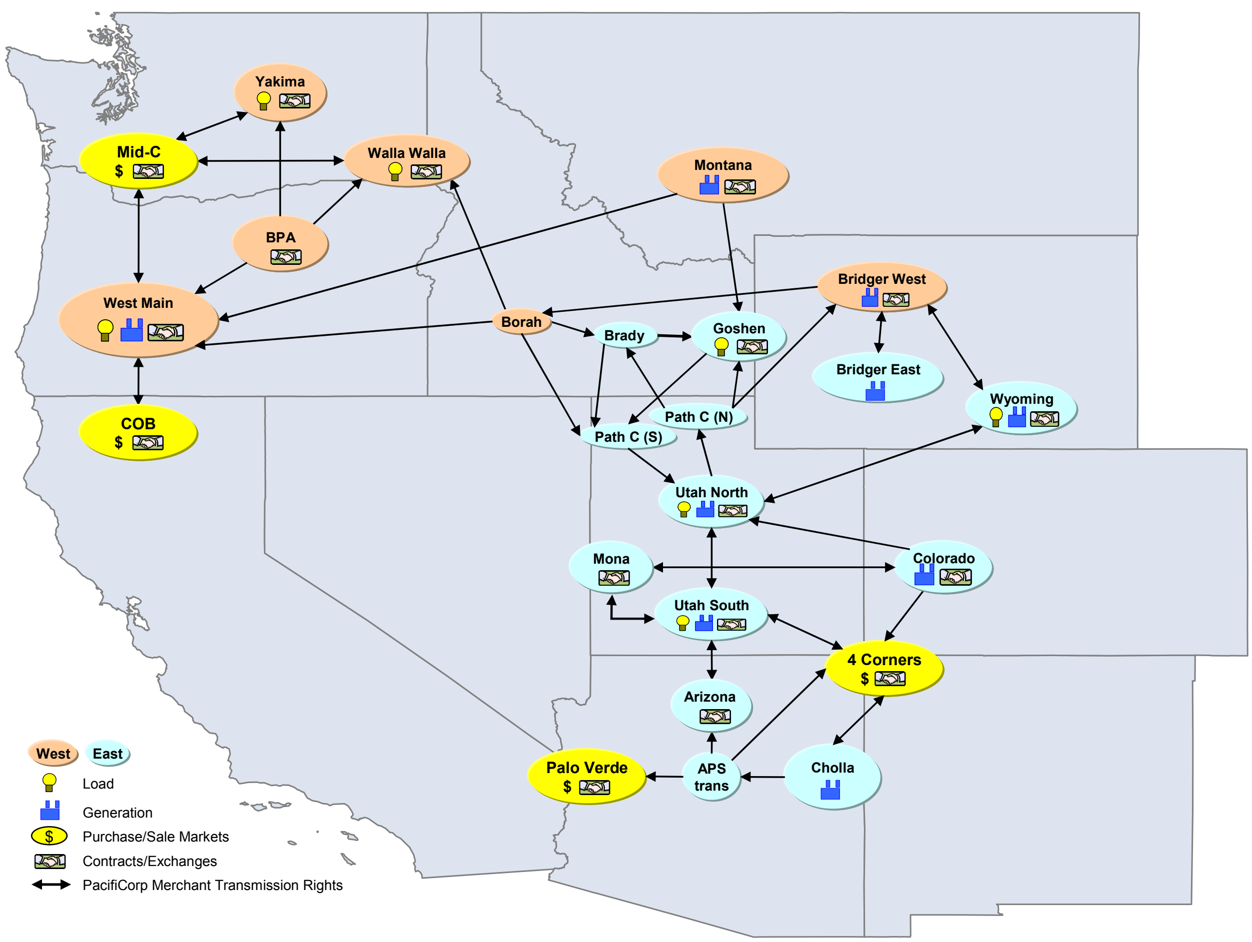
Losses

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.

Figure A.6 – IRP Transmission System Topology



APPENDIX B – DEMAND SIDE MANAGEMENT PROXY SUPPLY CURVE REPORT

This appendix contains the report Demand Side Management Proxy Supply Curve Report received from Quantec, LLC as requested by PacifiCorp to support demand side management resource modeling in the 2007 Integrated Resource Plan.

The original report is provided in an attached document:
"Quantec-DRProxyCurve-FinalReport_090706.doc"

Final Report

Demand Response Proxy Supply Curves

Prepared for:
PacifiCorp

September 8, 2006

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Table of Contents

I. Introduction

This report summarizes the results of an assessment of technical, market, and achievable potentials for demand response (DR) resources for PacifiCorp's system overall and its two control areas: West (California, Oregon, Washington), and East (Idaho, Utah, Wyoming). The results of this assessment form the basis for producing proxy supply curves for Class I and Class III demand-side management (DSM) resources, which will be incorporated into PacifiCorp's 2006 integrated resource plan (IRP).

The project's key objectives included: meeting PacifiCorp's IRP regulatory requirements; addressing public comments regarding comparable treatment of DR resources, with respect to power production options in PacifiCorp's resource portfolio evaluation; and assisting the company in further refining DR opportunities. Specifically, the project is intended to address an Oregon Public Utility Commission (OPUC) 2004 IRP requirement to evaluate Class I and Class III DSM resources, using a supply curve approach for portfolio modeling in PacifiCorp's 2006 IRP. In 2007, PacifiCorp plans to complete a more detailed assessment of DSM potentials, providing state-specific results. Therefore, this project is to be considered preliminary, and to serve as a "proxy" for the DR portion of that study.

The resulting supply curves show the price/quantity relationship for various categories of DR strategies and options within Class I and Class III DSM resources, as defined by PacifiCorp. As part of this project, to facilitate the economic screening of alternative DR options, research was also conducted regarding current utility practices in valuation of DR resources, with an emphasis on identifying key value drivers used in this evaluation.

This report is organized in five parts. The remainder of this chapter provides a general overview of DR resources, as well as the specific program concepts used in this study. Section II describes the results of research on DR value factors and valuation methods. Section III reports the results of the DR potential assessment. Section IV describes the general approach and methodology for estimating resource potentials. Detailed data and assumptions used to derive resource potentials for each specific DR resource are described in Section V.

Demand-Response Resources

Demand-response resources are comprised of flexible, price-responsive customer loads that may be curtailed in whole or in part during system peak load periods, when wholesale market prices exceed the utility's marginal power supply cost, or in the event of a system emergency. Acquisition of DR resources may be based on either reliability considerations or economic/market objectives. Demand response objectives may be met through a broad range of price-based (e.g., time-varying rates and curtailable rates) or incentive-based (e.g., direct load control) strategies. For the purpose of this project, DR is defined based on PacifiCorp's characterization in terms of two distinct classes of firm and non-firm resource options:

Class I (Firm) DSM Resources

This class of DR strategies allows either direct or scheduled interruption of electrical equipment and appliances such as water heaters, space heaters, central air-conditioners, commercial energy management systems, and irrigation pumps. Programmatic options in this class of resources fall into the four following categories:

- Fully dispatchable programs, 10 minute or less response, up to 87 hours annually (e.g., direct curtailment of residential air conditioning, water heating, space heating)
- Fully dispatchable programs, over 10 minute response, up to 87 hours annually (e.g., commercial energy management system coordination)
- Scheduled firm up to 170 hours annually (e.g., irrigation load curtailment)
- Scheduled firm at 360 or more hours annually (e.g., thermal energy storage)

Pre-determined incentive payments are typically the main instrument for compensating participants in this class of programs.

Class III (Non-Firm) DSM Resources

Demand response resources in this class differ from those in Class I in that their dispatch is outside the utility's control and, therefore, less reliable or "firm." Resources in this class include curtailable rate programs, time-varying prices (time-of use, real-time pricing, critical peak pricing), and demand buyback or demand bidding programs. Incentives are provided to participants either as a special tariff (curtailable rates, time-varying prices) or per-event payments (demand buyback).

Although residential seasonal programs such as Customer Energy Challenge are considered Class III resources, they are not included in this analysis. Arguably, such programs serve better as contingency resources during periods when energy prices are projected to be high and expected to stay high for an extended period of time, rather than as capacity relief resources.

Program Concepts

Before developing resource potential estimates, it is important to consider how each resource is likely to be structured as a demand response product or program. Using the definitions of Class I and Class III resources above, program concepts were developed as a framework for estimating market potential. For the purpose of this assessment, five specific program concepts were formulated, as described below.

Fully Dispatchable

Often referred to as direct load control (DLC), these fully-dispatchable programs are designed to reduce the demand during peak periods by turning off equipment or limiting the "cycle" time (i.e., frequency and duration of periods when the equipment is in operation) during system peak. The offerings for the residential sector are seasonally divided, while the potential with large commercial and industrial customers typically focus on summer cooling loads only. Three program concepts in this category of resources were included in the analysis:

- **Winter.** Direct load control of water and space heating during winter are the program options considered in this class. This program would be dispatched during the morning and evening peak hours. The largest potential for such a program will be in the West control area because of the higher saturation of electric space heating. Incentives are generally paid on a monthly basis. Although there are no large scale DLC programs in the Northwest, Portland General Electric (PGE) and Puget Sound Energy (PSE) have both studied implementation through pilot programs. Nationally, there are many utilities with space and/or water heating controls, including Duke Power, Wisconsin Power and Light, Great River Energy, and Alliant Energy.
- **Summer.** The main DR product in this group is direct load control of air-conditioning units[1], which are typically dispatched during the hottest summer days, and are common place due to the relatively high summer loads in warm climates. PacifiCorp currently pays monthly incentives to residential and small commercial participants in Utah's Cool Keeper AC Load Control program. There is approximately 130 MW of connected load for this program. Using a 50% cycling dispatch strategy, approximately half can be expected during an event. In addition to those utilities listed above, Nevada Power, Florida Power and Light, Alliant Energy, and the major investor-owned-utilities in California run air conditioner direct load control programs (e.g., Sacramento Municipal Utility District and San Diego Gas and Electric).
- **Large Commercial & Industrial.** Direct control of large commercial and industrial (C&I) customers requires coordination with the existing energy management systems (EMS). The focus of this program is adjustment of the heating, ventilation, and air conditioning (HVAC) equipment during the top summer hours. Incentives are generally paid on a per-kW or per-ton (of cooling equipment) basis. Some utilities running comparable programs include Florida Light & Power, Hawaiian Electric, and Southern California Edison.

Scheduled Firm

Program strategies that provide consistent reductions during pre-specified hours target customers with usage patterns and technology that allow scheduled shifting of consumption from peak to off-peak periods.

- **Irrigation Pumping.** Irrigation load control is a candidate for summer DR due to the relatively low load factor (approximately 30%) of pumping equipment and the coincidence of these loads with system summer peak. Through PacifiCorp's irrigation load control program, customers subscribe in advance for specific days and hours when their irrigation systems will be turned off. Load curtailment is executed automatically based on a pre-determined schedule through a timer device. Although a total of 100 MW

[1] Although it may be possible to add control of electric hot water heating to this summer program, this study does not address this option due to the declining saturations of electric hot water heating and the relatively low peak coincident demand during summer.

is contracted with this program, only half is available due to the alternating schedules of program participants. In the Northwest, Bonneville Power Administration (BPA) has run a pilot irrigation program (on a dispatch, rather than scheduled, basis) and Idaho Power has a program similar to that of PacifiCorp.

- **Thermal Energy Storage.** For small commercial and industrial customers, it is possible to have thermal energy storage (TES) cooling systems that produce ice during off-peak periods, which is then used during the on-peak period to cool the building. The system is programmed to use ice-cooling during pre-specified times (typically six hours per day, from April to October) and participants are given incentives on a per-kW or per-ton-of-cooling basis.

Curtailable Rates

Curtailable rate options have been offered by many utilities in the United States for many years. These programs are designed to ease system peak by requiring that customers shed load (in part or whole) by a set amount or to a set level (e.g., by turning off equipment and/or by on-site generation) when requested by the utility. Participants are either provided with a fixed rate discount or variable incentives, depending on load reduction; penalties are often levied for participants who do not respond to curtailment events. Large commercial and industrial customers are the target market for those programs that address PacifiCorp's summer system peak. Many utilities provide a broad range of program options, including Duke Power, Georgia Power, Dominion Virginia Power, Pacific Gas and Electric, ConEd, Southern California Edison, MidAmerican, and Wisconsin Power and Light.

Critical Peak Pricing

Critical Peak Pricing (CPP) rates only take effect a limited number of times during the year. In times of emergency or high market prices, the utility can invoke a critical peak event, where customers are notified and rates become much higher than normal, encouraging customers to shed or shift load. Typically, the CPP rate is bundled with a time-of-use rate schedule, whereby customers are given a lower off-peak rate as an incentive to participate in the program. Customers in all customer classes (residential, commercial, and industrial) may choose to participate in a CPP program, although there are certain segments in the commercial sector that are less able to react to critical peak pricing signals. Currently, there are no CPP programs being offered by Northwest utilities. Peak pricing is, however, being offered through experimental pilots or full-scale programs by several organizations in the United States, notably Southern Company (Georgia Power), Gulf Power, Niagara Mohawk, California utilities (SCE, PG&E, SDG&E), PJM Interconnection, and New York ISO (NYISO). Adoption of CPP has not been as widespread in the Western states as they have in the East. In the Pacific Northwest, this may be partly explained by the generally milder climate and the fact that, due mainly to large hydroelectric resources, energy, rather than capacity, tends to be the constraining factor.

Demand Buyback/Demand Bidding

Demand buyback and/or bidding (DBB) products are designed to encourage customers to curtail loads during system emergencies or high price periods. Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for the energy reduced during each event, based primarily on the difference between market prices and the utility rates. All major investor-owned utilities in the Northwest and Bonneville Power Administration have offered variants of this option, beginning in 2001. PacifiCorp's current program, Energy Exchange, was used extensively during 2001 and resulted in maximum reduction of slightly over 40 MW in that period. Demand reductions from PacifiCorp's current program are approximately 1 MW. Demand buyback products are common in the United States and are being offered by many major utilities. The use of DBB offerings as a means of mitigating price volatility in power markets is especially common among independent system operators including CAISO, NYISO, PJM, and ISO-NE. However, DBB options are not currently being exercised regularly due to relatively low power prices.

II. Valuation of Demand Response Resources

Overview

In the Northwest and elsewhere in the country, valuation of DR programs has been the subject of much debate among utility industry experts. Although there is broad agreement on the existence and relevance of a wide range of benefits arising from DR, there is little agreement on how and to what extent these benefits can be attributed to specific DR programs and what metrics might be used to quantify them. In response to this, in 2005 the Northwest Power and Conservation Council sponsored a series of workshops to identify and enumerate value attributes of DR resources and to develop a consistent methodology for their valuation. The Demand Response Research Center in California recently commissioned two parallel studies to investigate alternative frameworks for valuation and cost-effectiveness analysis of DR products.

As part of this study, we conducted a thorough search of DR literature, evaluation reports, and utility filings, followed by informal interviews with several industry experts to investigate current practices for evaluating DR resources. The results of this analysis are intended to inform PacifiCorp's process for screening DR resource options and how they might be incorporated in its integrated resource plan. We begin this section with a review of potential benefits and value factors ascribed to DR, discuss the current practices and the basis for valuation of these benefits, and then consider alternative approaches for incorporating DR options in the integrated resource planning process.

Benefits of Demand Response

There are many different views on the types and the relative importance of value factors associated with DR. Industry experts agree on at least three general categories of benefits from DR: economic, system reliability, and environmental (Hirst 2001).

Economic Benefits. There is a host of economic benefits to the utility, the consumers, and the power system as a whole that are presumed to arise from DR. Some of these benefits are more tangible and more readily quantifiable than others. Cost avoidance and cost reduction are the main economic drivers for DR. Demand response allows utilities to avoid or defer incurring costs for generation, transmission, and distribution, including capacity costs, line losses, and congestion charges. Economic benefits may also accrue directly to participants in the form of incentives, rate discounts, and greater ability to adjust their loads to prices, thereby gaining greater control over their energy use and managing their energy costs (Braithwait, 2003). DR has also been credited with several harder to quantify economic benefits, such as creating a hedge against market exposure (price objectives), helping create a more elastic demand curve by sending appropriate price signals (elasticity objectives), and reducing the overall market price by alleviating pressure on reserves (market efficiency objectives) (Ruff, 2002).

System Reliability Benefits. Demand response reliability considerations are those meant to ensure reliability in power supply and delivery during system emergencies by providing the ability to shed load under emergency conditions. Customer demand management can enhance reliability of the electric supply and delivery systems by providing the utility with the means to better balance loads with supply during system emergencies and/or high-use periods. In this context, DR can help improve the adequacy and security of the power supply and delivery (T&D) systems by augmenting the utility's ancillary services, such as supplemental reserve (Hirst, 2002).

Potential Environmental Benefits. Demand response resources promote the efficient use of resources in general. Depending on the generation fuel mix of the sponsoring utility, this can help reduce externalities in power generation and reduce emissions. Increasingly, utilities have begun to consider the potential effects of future carbon taxes in their DR product design.

Although this is by no means an exhaustive list of all potential benefits discussed in DR literature, it represents the most common set of benefits recognized by industry experts. Additional benefits such as risk management, market power mitigation, customer service, and third-party benefits (for example to aggregators and service providers) have also been cited as potential benefits of DR. These benefits, however, generally tend to be less pronounced and difficult to quantify (Peak Load Management Alliance, 2002). Approaches and current practices for evaluating DR resources and quantifying each of the above benefit categories are discussed below.

Resource Valuation Methods

Current practices in valuation of DR resources largely rely on an extension of the "Standard Practice Manual" (SPM) originally developed in California for evaluating energy-efficiency programs (California Public Utilities Commission, 2001). Of the four tests set forth in the latest version of the SPM, published in 2001, the total resource cost test (TRC), usually accompanied by the participant test, is the most common method used to screen DR resources by utilities (California Public Utilities Commission, 2003).[2] A clear instance of the application of SPM to the evaluation of DR resources is found in the California Public Utilities Commission's direction that the SPM be used as an option in evaluating DR, "since it allows an assessment of demand reductions from multiple viewpoints: society, customer, utility, and ratepayer."

A review of current practices in valuation of DR benefits indicates that not all benefits discussed above are taken into account by utilities or system operators, mainly due to the fact they tend to be hard to quantify. Potential benefits of DR, common basis for their valuation, and the range of suggested values are summarized in Table 1. Current valuation methods and practices are discussed in greater detail below.

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2 The other tests are the Ratepayer Impact Measure (RIM) Test, Participant Tests, and the Program Administrator (or Utility) Test.

Table 1. Potential Benefits of Demand Response

Benefit Category	Value Factors	Basis for Valuation	Range of Values
Market-wide	• Overall economic efficiency (better alignment of supply and demand) • Reduction in average price of electricity in the spot market • Reduced costs of electricity in bilateral transactions • Reduced hedging costs, e.g., reduced cost of financial options • Reduced market power • Private entity (e.g. aggregator) benefits	Not Quantified	Not Applicable
Utility System	• Avoided capacity costs (generation) • Avoided energy costs • Avoided T&D losses • Deferred grid system expansion	Benchmarking (peaker unit) Benchmarking (market prices) Adders Marginal (local) T&D costs	\$50-\$85 Variable 6%-10% Variable
Customer	• Incentives • Reduced power bill (participants) • Greater choice and flexibility	Value of payment Rates, demand charges Cash-flow, Option model	Variable Variable Variable
Reliability Benefits	• Increase in overall system reliability • Value of insurance against low-probability/high-consequence events • Option value (added flexibility to address future events) • Portfolio benefits (increase in resource diversity)	Change in LOLP Value of un-served energy (customer outage costs) Not Quantified Not Quantified	Not Available \$3-\$5 per kWh Not Applicable Not Applicable
Environmental Benefits	• Avoided emissions • Avoided future carbon taxes	Environmental "adder" Not Quantified	8%-12% Not Applicable

Valuation of Economic Benefits

With the exception of participant tests, the application of the SPM tests rely on the concept of cost avoidance as the key mechanism for taking into account the economic value of DR. The TRC test, which is often used as the primary criterion for screening of DR resources, takes into account a variety of avoided costs associated with generation, transmission, distribution, and line losses. The avoided capacity and, to a lesser extent, energy costs are the principal economic benefits included in the test. Determination of avoided capacity and energy costs are most commonly based on a benchmarking method. In the case of avoided capacity costs, the approach relies on using average per-unit life cycle cost of a peaker resource (usually a combined- or simple-cycle gas turbine) as a benchmark for screening of DR options. Market price curves are the most commonly-used proxy for determination of avoided energy costs.

Avoided capacity costs tend to vary across utilities and the program to which they are applied. Regardless of how they are calculated, capacity costs used by most utilities surveyed fall in the range of \$50 to \$85 per kW-year. In a recent ruling, the California Public Utilities Commission authorized an avoided cost of $52 per kW as compared to the previously established avoided cost of $85 per kW, based on the average life-cycle cost of a peaker plant method for screening and valuation of DR resources (CPUC, PG&E Application 05-06-028, 2005).

Avoided energy costs represent additional benefits from DR programs. Since most DR programs lead to a shift (rather than a reduction) in energy use, the energy benefits are typically measured in terms of on-peak/off-peak price differential. Other DR programs, such as DLC may result in reductions in energy use, since some portion of the foregone energy use may not be offset by additional consumption during the off-peak period. The latter benefits are especially important in evaluating DR programs from the participants' point of view, since they tend to directly affect bills. Avoided energy costs have been used to measure the benefits in a number of evaluations of DR programs in the Northwest.[3] Avoided energy costs are also the sole basis for determination of payments in demand buyback and demand bidding programs. Indeed, incentives in all demand buyback programs are structured on the basis of market energy prices, rather than avoided capacity costs.

Benefits to the grid system generally fall into two categories: 1) avoided line loss; and 2) value of opportunities to defer system expansion. In the Northwest, both PacifiCorp and PGE have explicitly incorporated avoided T&D losses in their past evaluations of time-of-use and direct load control programs, and Bonneville Power Administration has explicitly included deferral of investments transmission system expansion in its system planning and valuation of DR programs.

Direct benefits to customers represent additional benefits likely to result from DR. These benefits generally appear in the form of incentive payments from the utility or lower bills resulting from reductions in demand charges, shift of demand to lower-priced, off-peak periods and potential energy savings. As discussed above, in the case of DR programs involving a shift in consumption, these benefits tend to be small. In many DR programs, such as time-of-use rates and load control/curtailment programs, portions of the foregone energy use during DR events (high rate or curtailment period) may not be compensated by higher use during off-peak period, thus resulting in net reductions in the customer's energy consumption.

Other potential benefits to customers, such as greater choice and "option value," are generally more difficult to quantify. Attempts at quantification of these benefits generally rely on either a discounted cash-flow analysis or an "option model" (see Sezgen 2005).

Valuation of System Reliability Benefits

The planning and screening of utility-sponsored DR programs typically have not included reliability benefits. But reliability has been the primary metric for valuation of DR programs offered by independent system operators (ISOs). Most of the seven established ISOs have been actively engaged in offering DR options. Since the primary goal of an ISO is to maintain system reliability, it stands to reason that valuation of their programs would be based on reliability

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3 These include evaluations of irrigation load curtailment and pilot time-of-use programs offered by PacifiCorp, evaluations of residential time-of-use and direct load control programs by PGE, and Bonneville Power Administration's evaluation of remote irrigation load control.

benefits rather than avoided generation capacity. Indeed, evaluations of ISO-sponsored programs completed to date have focused almost exclusively on reliability benefits based on avoided congestion, valued in terms of the location-specific marginal transmission costs (LMC).

The general approach used in valuation of ISO-sponsored DR is based on two factors: 1) the difference between market power price and the DR program costs; and 2) the expected marginal value of increased reliability realized through assumed reductions in loss-of-load probability (LOLP) and its impact on the expected value of un-served energy (EVUE) as a function of the value of lost load (VOLL), that is:

$$EVUE = \text{Value of Lost Load (VOLL)} * \Delta\ LOLP * \text{Load at Risk}$$

The underlying concept in the evaluation approach is that the value of curtailable load (therefore the value of the DR programs that generate it) is a function of the "expectation" of future loss of load. This suggests that the actual value of DR programs stems primarily from their societal value as a hedge against low-probability, high-cost events and the associated outage costs to customers.

The NYISO and ISO-NE have both used this approach in evaluation of their DR products (RLW Analytics, 2005). Calculation of changes in LOLP and the value at risk are generally established on an event-by-event basis and tend to be highly variable. In its evaluations, the NYISO, for example, typically has assumed a VOLL of $5.00/kWh (NYISO, 2004); and the PJM Interconnection recently proposed a VOLL of $20/kWh. However, as data on several real-time pricing programs suggest, the VOLL tends to fall in the range between $3/kWh and $5/kWh (Barbose 2004, Violette 2006). Available estimates of VOLL are calculated from the customer's or societal perspectives and are generally expressed in terms of energy, rather than capacity. Presumably, given the actual, program-specific hours of curtailment, it may be possible to convert these estimates to an equivalent capacity value.

Valuation of Environmental Benefits

Demand response has the potential to produce tangible environmental benefits by avoiding emissions from the operation of peak units as well as potential conservation effects (load shed versus load shift) during peak periods. Such environmental impacts, however, depend entirely on the emissions profile of the utility's generation resource mix. It is also possible that reduced emissions during peak periods might be offset by increased emissions during off-peak periods, as well as from additional emissions from on-site, back-up generation at commercial and industrial facilities. Due partly to these complexities, potential environmental benefits are not currently being considered in valuation of utility-sponsored DR programs.

Treatment of DR Options in Integrated Utility Resource Planning

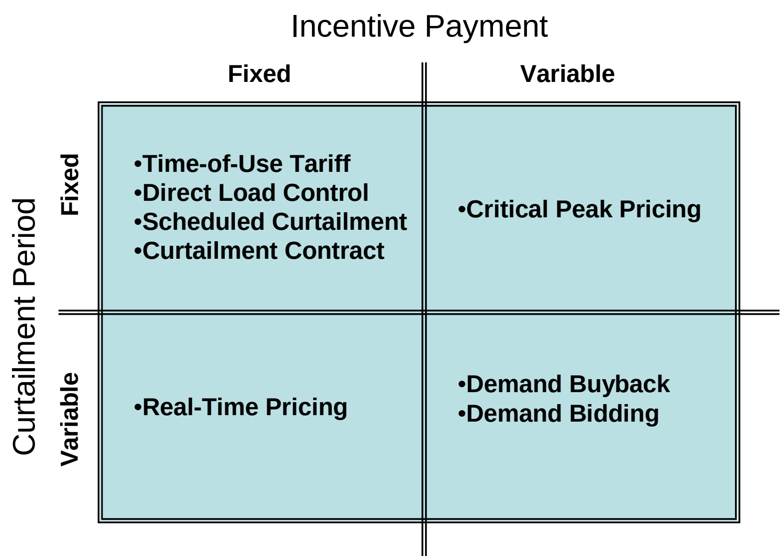
Classification of DR Options

Values arising from DR options, and the manner in which they are incorporated in the integrated planning process may vary by the type of DR product and the entity that sponsors them. There have been several attempts at classification of DR programs. The most common approach to classification of DR involves characterizing them according to the degree of the utility's dispatch control. From this perspective, DR resources are generally categorized according to a "firm" versus "non-firm" dichotomy. Another approach, adopted in the recent report by the U.S. Department of Energy, classifies DR programs in terms of the basis on which participants are compensated and proposes two categories: tariff-based and incentive-based (DOE, 2006). A third approach, suggested in a recent study sponsored by the Rocky Mountain Institute (Rocky Mountain Institute, 2006), classifies DR resources along two dimensions: 1) the criteria that trigger a curtailment request by the utility (economic versus reliability); and 2) the method by which utilities motivate customers to participate in DR (load response versus price response).

These approaches, however, generally do not provide guidance as to how DR benefits and costs might be allocated or how various resources might be modeled in an integrated resource plan. Arguably, from a utility's perspective, the most important benefits of DR are economic (reducing the overall supply cost) and reliability (offering an optional resource in case of system emergencies).

An alternative, and perhaps more appropriate, classification of DR would be in terms of the degree of variability in curtailment period and prices paid by the sponsoring utility.[4] Under this scheme, DR resources are classified in terms of two dimensions: curtailment period and incentive payment. As shown in Figure 1, both period of curtailment and the level of incentives paid by the utility to motivate curtailment may be either fixed or variable. (See Neenan, 2006.)

Figure 1. Classification of Demand Response Programs



4 Time-of-use rates and critical peak pricing are examples of programs where both pricing period and price levels are fixed. Demand buy-back and demand bidding demand response strategies are examples of programs where both price periods and levels of payment are variable.

Time-of use, load control, scheduled curtailment, and curtailment contracts are examples of resources where both incentive payments and curtailment periods are fixed in advance. Although this group of programs offers more *predictable* prices and, to a lesser extent, amounts of reduction, they also pose a degree of price risk in that program prices are set in advance through the use of price forecasts rather than based on actual prices at the time of load reduction. Demand buyback and demand bidding, on the other hand, are resources where both curtailment period and incentive payments are variable.

Incorporating DR into the IRP Process

Much the same as energy efficiency resources, DR products may be incorporated into the IRP in two ways. The first approach, often referred to as “decrementing,” begins with pre-screening of DR resources for general cost-effectiveness based on an external benchmark (generally avoided capacity costs), decrementing the load forecast by the amount of DR resources that pass the screening, and solving for the true avoided cost as derived from the value of decremented load to the resource portfolio. The second approach entails simultaneous modeling of generation and DR resources in the context of an optimization or system expansion planning model and selecting the optimal, least cost, mix of resources. In our view, the latter approach is preferred in that it treats DR resources on a level playing field with supply options and forces the model to select from the most attractive, least-cost mix of resources regardless of their classification as supply or demand-side.

The main shortcoming of these approaches to valuation and integration of DR resources is that they generally focus on economic (cost-reduction) benefits of DR and ignore the reliability benefits. Moreover, the economic benefits of DR often are measured in terms of energy, rather than capacity, values. For most DR resources, the benefits ought to be evaluated primarily in terms of an alternative, “optional” capacity resource and secondary energy benefits (in terms of both reduced consumption and/or peak-off-peak energy costs differential). Regardless of the method used, it is important that the full range of economic values (including avoided capacity, energy, and T&D benefits, as well as reliability benefits) be fully considered in the screening and planning processes. Although the greatest value of DR options is likely to be on the generation side, additional benefits such as avoided T&D losses and reliability benefits may be incorporated in the valuation as utility-specific “adders.”

An additional shortcoming of these approaches is that they ignore the role of risk and uncertainty associated with various resource options. Clearly, there are technical (e.g. equipment failure) and market (e.g. program and event participation rates) uncertainties inherent in any demand-response option. These risks need to be explicitly taken into account in screening of DR resources. It is equally important in the context of IRP that the treatment of DR risks be symmetrical; that is, the screening process ought to also take into account upside risks of DR. Since DR resources are valued on the basis of expected future loads and power prices, future fluctuations in loads and avoided costs are likely to have a direct effect on the value of DR options.[5]

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[5] Portfolio management principles and techniques are being used in a limited way by some utilities to analyze uncertainties in the IRP process. This is particularly the case in designing standard renewable portfolios in several

In the context of IRP, joint consideration of economic (capacity and energy) and reliability benefits does, however, pose additional complexity. Since integrated resource planning processes are generally based on long-run resource needs, the value of DR hinges on its ability to displace some portion of the utility's peak demand. As pointed out in the Department of Energy's recent report, once DR resources are included in the utility's capacity resource mix, they become part of the planned capacity and are no longer available for dispatch during system emergencies (DOE, 2006). It is important, therefore, to distinguish between DR resources that serve the economic objectives and might be incorporated in the resource plan and those that are more appropriately set aside for reliability purposes. Certain DR resources, such as demand bidding or demand buyback, may be set aside as reliability options to be called upon during system emergencies.

Potential adverse customer impacts are additional considerations in DR planning. Clearly, once DR resources are incorporated in the planned capacity, the utility can maximize the value of DR resources by exercising these options to the maximum extent possible. However, the more frequently these options are exercised, the higher the likelihood of more severe disruptive impacts of the customers' operations. This will affect the customers' decision to participate in the DR program and thus reduce the market potential for DR.

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jurisdictions. For a discussion of uncertainty in IRP and the portfolio management approach see Awerbuch (1993 and 2005). Also see Bolinger (2005) for a survey of current utility practices in portfolio design.

III. Demand Response Resource Potentials

The approach to estimation of resource potentials in this study distinguishes between three definitions of demand-response potential that are widely used in utility resource planning: technical, market, and achievable potentials. Technical potential assumes that all demand-response resource opportunities may be captured regardless of their costs or market barriers, notwithstanding obvious exceptions such as load control in mission-sensitive operations. Market potential, on the other hand, represents that portion of technical potential that is likely to be available over the planning horizon, given resource constraints and prevailing market barriers. Finally, achievable potential recognizes that not all of the market potential can be implemented due to the overlap (or interaction) among DR options targeted for the same sectors and/or end uses.

To the extent possible, we have sought in this study to obtain the most recent and reliable data on market prospects for various DR options, relying upon available resources from other utilities offering similar products. However, information and assumptions based on current demand response experiences and costs, no matter how accurate, are subject to future uncertainty. Therefore, the results of this study are to be viewed as preliminary and indicative rather than conclusive.

The general methodology and analytic techniques used in this study conform to standard practices and methods used in the utility industry. Given the scope and timeframe of this study, it was necessary to utilize a consistent and relatively simple methodology to effectively address PacifiCorp's immediate IRP needs. The methodology and inputs assumptions are fully described in Sections IV and V of this report.

Technical Potential

In the context of demand response, technical potential assumes that all applicable end-use loads, in all customer sectors, are at least partially available for curtailment, except those customer segments (e.g., hospitals) and end uses (e.g., restaurant cooking loads) that do not lend themselves to curtailment,[6] and for those programs (e.g., direct load control) that utilize cycling strategies.

Table 2 provides for each customer class (industrial, commercial, irrigation and residential) the technical potential in MW at the system level. (Separate results for the East and West control areas are provided in Appendices 1 and 2.) From a strictly technical perspective, critical peak pricing is expected to have the largest potential due to its broad-based eligibility, followed by curtailable rates and demand buyback. In the absence of market constraints, these figures should

[6] Although hospitals generally rely on some on-site generation capability, which may be called upon by the utility as a dispatchable resource, such resources are not being considered in this study. Arguably these units are likely to be needed by the host facility during the same period as the utility and are therefore unlikely to be made available for dispatch.

be viewed largely as estimates of “technical feasibility” only and a measure of the total load that is technically available for demand response.

Table 2. Technical Potential (MW), System

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	194	- - -	- - -	510	531	500
Commercial	- - -	55	50	-	93	133	232	130
Irrigation	- - -	- - -	-	381	- - -	- - -	- - -	- - -
Residential	374	351	-	- - -	- - -	- - -	618	- - -
Total	*374*	*406*	*244*	*381*	*93*	*642*	*1,380*	*630*
% of System Peak	*4%*	*5%*	*3%*	*5%*	*1%*	*8%*	*16%*	*7%*

To provide an illustration of the methods used to estimate technical potentials, the fully dispatchable winter program will be used. First, eligibility for this program is limited to residential customers due to low saturation of electric space and water heating in other customer classes. Next, PacifiCorp energy sales and system and end-use load shapes indicate that the total residential space and water heating loads during the top 87 hours of the winter average approximately 580 MW and 250 MW, respectively. Although DLC programs can fully interrupt this load when installed, it is assumed that a 50% cycling strategy is used, and only 90% of this is technically available to account for the fact that not all systems can be retrofitted with DLC equipment. Therefore, the system-level technical potential, as shown in Table 3, is 374 MW.

Market Potential

Market potential is the subset of technical potential that may reasonably be accessible by program strategies, accounting for market barriers and customers’ ability and willingness to participate in demand response programs. For the majority of demand response options, market potentials are estimated by adjusting technical potential by two factors: expected rates of “program” and “event” participation. For all programs options, estimates for both program and event participation are derived based on the experiences of PacifiCorp and other utilities offering similar programs. In the case of curtailable rates and demand buyback, market potentials are estimated based on observed price elasticity of load response. See Figure 2 for a comparison of technical and market potentials for various program options.

As shown in Table 3, curtailable rates have the highest market potential (144 MW), followed by summer DLC and irrigation.

Figure 2: Technical and Market Potential (MW), System

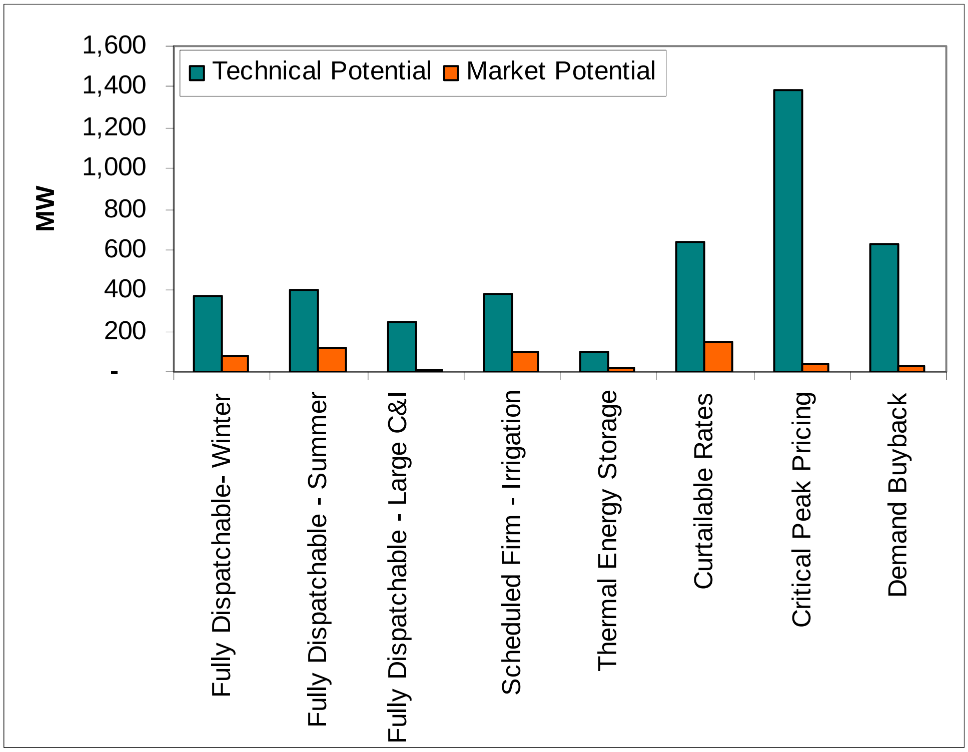

Table 3. Market Potential (MW), System

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	5	- - -	- - -	115	14	22
Commercial	- - -	3	1	- - -	19	30	6	6
Irrigation	- - -	- - -	- - -	95	- - -	- - -	- - -	- - -
Residential	75	118	- - -	- - -	- - -	- - -	17	- - -
Total	*75*	*120*	*7*	*95*	*19*	*144*	*37*	*28*
% of System Peak	*0.9%*	*1.4%*	*0.1%*	*1.1%*	*0.2%*	*1.7%*	*0.4%*	*0.3%*

For a fully dispatchable winter program, an expected load participation rate of 20% (based on experience of similar programs) and event participation rate of 100% are assumed. This assumption is based on the fact that, absent customers' ability to override curtailment and no equipment failure, load interruption would occur once the load is dispatched by the utility.[7]

[7] Reliability of direct load control systems is primarily a function of the type of equipment and communication systems used to affect control such as radio frequency, telephone networks, wide-area networks, or power line carrier systems. Historical experience with systems has shown that the assumption of a zero failure rate may be unjustified.

Based on these assumptions, this program could reasonably be expected to provide approximately 75 MW of load reduction for the PacifiCorp system.

Using price elasticity of load participation and a measure of commercial and industrial customers' willingness to participate in demand buyback, market potential for this option is estimated at 28 MW. As discussed in Section IV of this report, the elasticity estimates were calculated based on data available on 2000-'01 demand buyback program experience of Northwest utilities. Data available on PacifiCorp's 2000-'01 Energy Exchange program indicate approximately 40 MW of reduction at an average cost of approximately $100 per MWh. The estimated 28 MW of future market potential may prove overly optimistic due to the dramatically different market conditions prevailing today. Reductions similar to those achieved in 2000-'01 could be difficult or impossible to repeat if electricity prices and customer concerns over energy market conditions continue to be low. Indeed, based on PacifiCorp's program records, operation of the Energy Exchange program during the past three years has resulted in a maximum reduction of no more than 1 MW.

Achievable Potentials

In analyzing levels of achievable potential it is important to take into account two factors: resource interactions and load reduction being achieved given existing programs. Achievable potentials, therefore, represent unique impacts of various DR program options net of the impacts of existing programs. Estimates of market potentials presented above provide "stand alone" estimates of potential. In calculating achievable potential, it is also important to take into account the interaction among DR programs that target the same customer sector and/or end uses within the same sector. Generally, interaction may be accounted for by first ranking competing programs by levelized cost and then allocating the market potentials based on an "availability" factor[8].

For the purpose of this study, we have assumed that DBB and scheduled firm irrigation are fully available; therefore they have been assigned an availability factor of 100%. Since curtailable rates and dispatchable large C&I compete for the same target market as DBB, only a portion of their market potential will be available. In the residential and small commercial sector, the summer DLC program is fully available; however, thermal energy storage would only be partially available as it competes with the commercial sector DLC program option.

As shown in Table 4, the DR options considered in this analysis may be expected to provide 373 MW of capacity for the PacifiCorp system. In 2005, the PacifiCorp system peaked at 8,940 MW with 570 MW and 1,540 MW of load occurring during the top one percent and ten percent of the load duration curve. The estimated achievable potentials for DR provide the opportunity to offset 66% of the top one percent and 25% of the top ten percent of the system peak load.

[8] Technically, this is the percentage of the market potential that remains after accounting for resource interactions. For example, a 25% availability factor would be multiplied by the market potential to arrive at the achievable potential on a program-by-program basis.

Summer DLC (120 MW), irrigation (95 MW), and curtailable rate (72 MW) are expected to provide the highest levels of achievable potential. Yet, approximately 114 MW of the identified potential is already under contract through PacifiCorp's Cool Keeper (65 MW), irrigation load curtailment (48 MW), and Energy Exchange (1 MW), resulting in a remaining achievable potential of 259 MW. Therefore, in addition to achievable potential, Table 4 also provides potential net of current programs.

Table 4. Achievable Potential (MW) – System

	Fully Dispatchable			Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Achievable Potential	37	120	3	95	9	72	7	28	373
Current Program MW	- - -	65	- - -	48	- - -	- - -	- - -	1	114
Potential Net of Current Programs	37	55	3	47	9	72	7	27	259

Proxy Resource Supply Curves

Supply curves are constructed to show the relationship between the cumulative quantities of DR resources and their costs. Development of supply curves first requires the estimation of per-unit costs. Demand response strategies vary significantly with respect to both type and cost levels. Applicable resource acquisition costs for DR generally fall into two categories: 1) fixed direct expenses such as infrastructure, administration, maintenance and data acquisition; and 2) variable costs. In the category of fixed cost, this study distinguishes between initial development and on-going program administration and operation costs. Variable costs also fall into two categories: costs that vary by the number of participants (e.g., hardware costs) and those that vary by kW reduction (primarily incentives).

Although a large number of national programs were researched for this project, the reporting of costs, particularly development and ongoing administrative costs, were found to be either unavailable or difficult to measure. For the purposes of this study, to the extent possible, we have relied primarily on administrative costs associated with PacifiCorp's other, similar programs, or have adopted rough estimates available from other utilities. See Section IV for specific cost assumptions for various DR options.

In developing proxy supply curves, all program costs were first allocated annually over the expected program life cycle (10 to 15 years) discounted by PacifiCorp's real cost of capital at 5.1% to estimate the per-kW levelized[9] costs for each resource. Resources were then ranked based on their levelized costs along the supply curve. Figure 3 displays per-unit costs for the various DR options.

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9 Levelized costs represent the annual contract cost, per kW/year, for each DR option. This approach provides means for treating all DR on a consistent basis with supply alternatives in the IRP framework.

Figure 3: Levelized Resource Costs ($/kW/year)

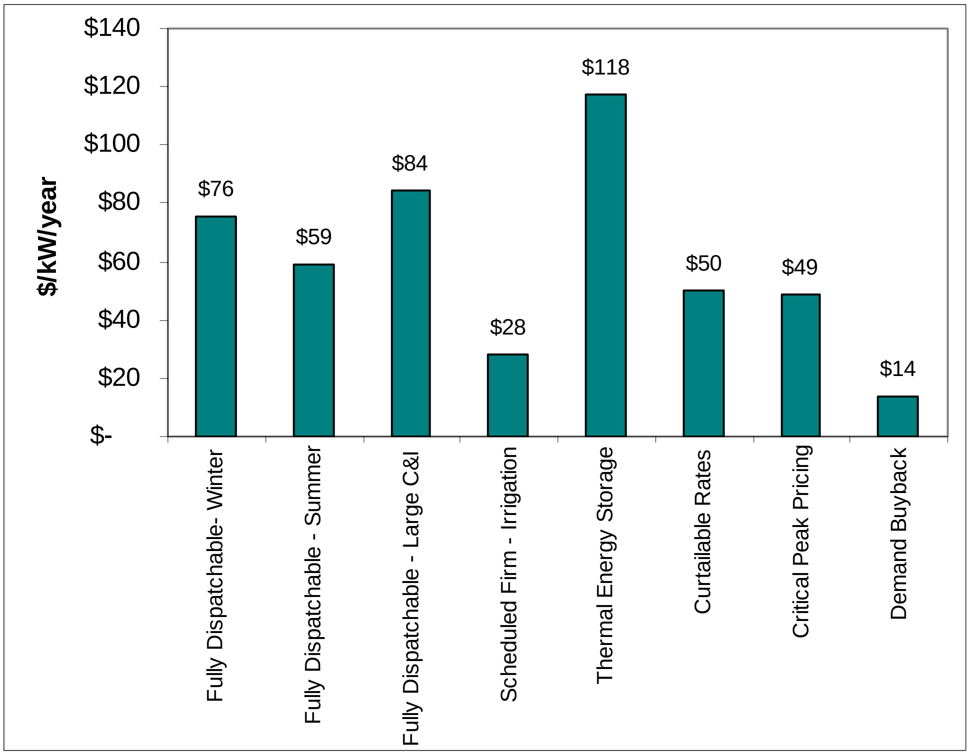
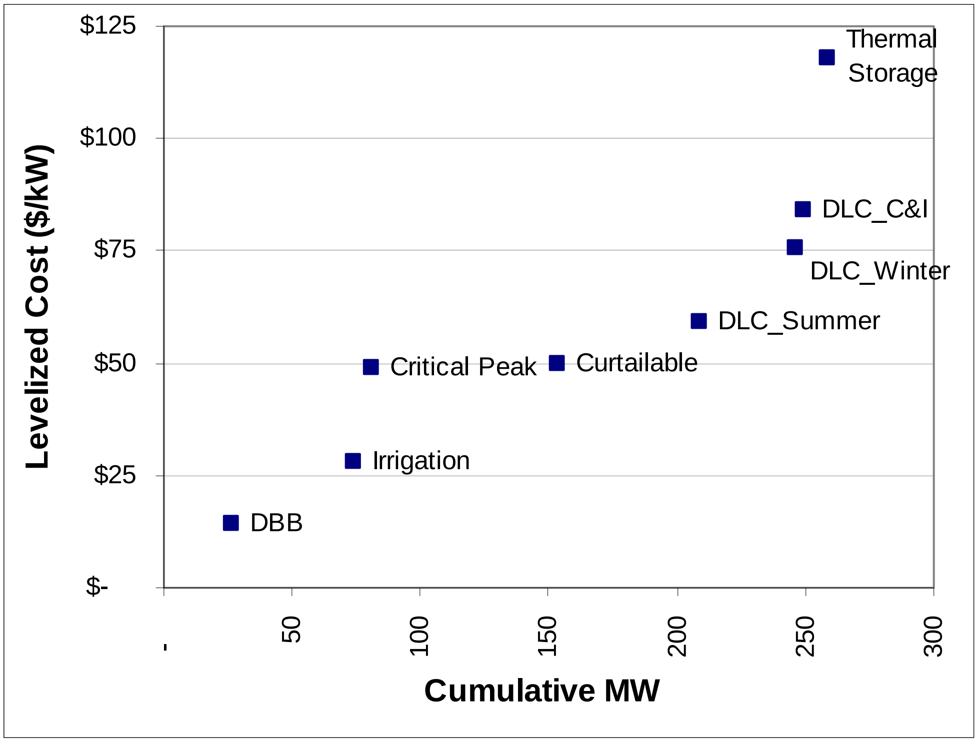


Figure 3 indicates that, with the exception of the irrigation program, per-unit costs tend to increase with the level of firmness of the load: the more reliable the load reduction, the more costly the program. Demand buyback, at $14/kW/year, is expected to be the least expensive option. This program, although relatively inexpensive, provides possibly the least reliable load reduction among the eight program options.

Firm irrigation is the next lowest-cost resource at $28/kW/year. Because reductions by this program are pre-determined and scheduled, it is an effective program for achieving firm seasonal load reductions. However, its value as a reliability option is limited because 100% capacity reductions are already incorporated into the utility's planned resource capacity, and hence cannot be "called" to provide load relief during system emergencies. Critical peak pricing ($49/kW/year) provides the ability to notify customers of curtailment events; national experience indicates the potential for reductions can be significant, but customer acceptance and response have generally been lower than expected. Curtailable rate programs ($50/kW/year) may provide additional dependability due to contract requirements on customers and may serve as an effective option for reliability purposes. Owing mainly to hardware costs and incentives required of fully dispatchable resources, per-unit costs for the three direct load control programs exceed $59/kW/year. Finally, thermal energy storage is expected to be the most costly option with a per-unit cost of $118/kW/year.

The proxy supply curve for the eight resource options investigated in this study was constructed based on estimated achievable resource potential net of current programs and per-unit cost of each resource option. Figure 4 displays graphical presentation of the supply curve, which represents the quantity of resources (cumulative MW) that can be achieved at or below the cost at any point. Cumulative MW is created by summing the achievable potential net of current programs along the horizontal axis sequentially, in the order of their levelized costs. For example, the irrigation program has 47 MW available, and its cost is second lowest. Therefore, its quantity is added to the 27 MW of DBB, showing that in total, 74 MW of resources are available at prices equal to or less than $28/kW.

Figure 4. Cumulative Supply Curve, System



Resource Potential Scenarios

High and Low

For the purpose of IRP modeling, achievable potentials were estimated under three scenarios: base case, high, and low, corresponding with PacifiCorp's projected on-peak market prices of $40/MWh (low), $60 (base) and $100 (high). To account for the relationship between market prices (and incentives) and program potential, high scenarios generally assume aggressive marketing efforts and higher incentive levels and, therefore, higher program participation. The low scenario reflects a less aggressive marketing effort and relatively weak program participation. (See Sections IV and V for assumptions underlying the two scenarios.)

The high and low scenarios for the DBB and curtailment contract options were constructed based on load response elasticity estimates. As reported in the 2006 Department of Energy's Report to Congress, commercial and industrial customers have typically exhibited an inelastic response to prices (elasticity = 0.1) in load curtailment. This figure was used as a basis for the high and low program participation scenarios for the fully dispatchable large commercial and industrial and curtailable rates options. For the DBB program, a price elasticity of 1.45, estimated based on the 2000-2001 regional data on demand buyback programs, was used to develop the high and low scenarios. (See Section IV for a discussion of methodology and data.)

The results for the three scenarios are shown in Table 5. Generally, as the potential increases, so does the per-unit costs, due to higher incentives and marketing costs. Yet, in a few cases, such as critical peak pricing and fully-dispatchable commercial and industrial programs, per-unit costs are expected to fall from the low to the base case due to economies of scale; lower marginal per-unit costs result from the fact that fixed program costs are spread over a larger number of units.

Table 5. High, Base, and Low Costs and Quantities System

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Low								
Achievable Potential MW	19	80	1	76	7	30	1	9
Resource Costs ($/kW/yr)	$58	$53	$167	$29	$115	$39	$91	$13
Base								
Achievable Potential MW	37	120	3	95	9	72	7	28
Resource Costs ($/kW/yr)	$76	$59	$84	$28	$118	$50	$49	$14
High								
Achievable Potential MW	56	141	9	114	12	88	14	65
Resource Costs ($/kW/yr)	$84	$72	$102	$37	$119	$86	$45	$18

Treatment of Metering Costs

The DR scenarios presented above include metering costs, where applicable (please see Section V for detailed assumptions). In the future, these costs may not be necessary if advanced metering technology is implemented in PacifiCorp's territory. Therefore, this additional scenario excludes metering costs from the base estimates of per unit cost. Figure 5 below displays the new figures and Table 6 provides a comparison of the base (with metering) scenario and the alternative (without metering). The exclusion of meter costs makes little difference (less than $1/kW/year) in all programs, except critical peak pricing where the reduction equals $7 /kW/year.

Figure 5. Per Unit Resource Costs – Excluding Metering Costs

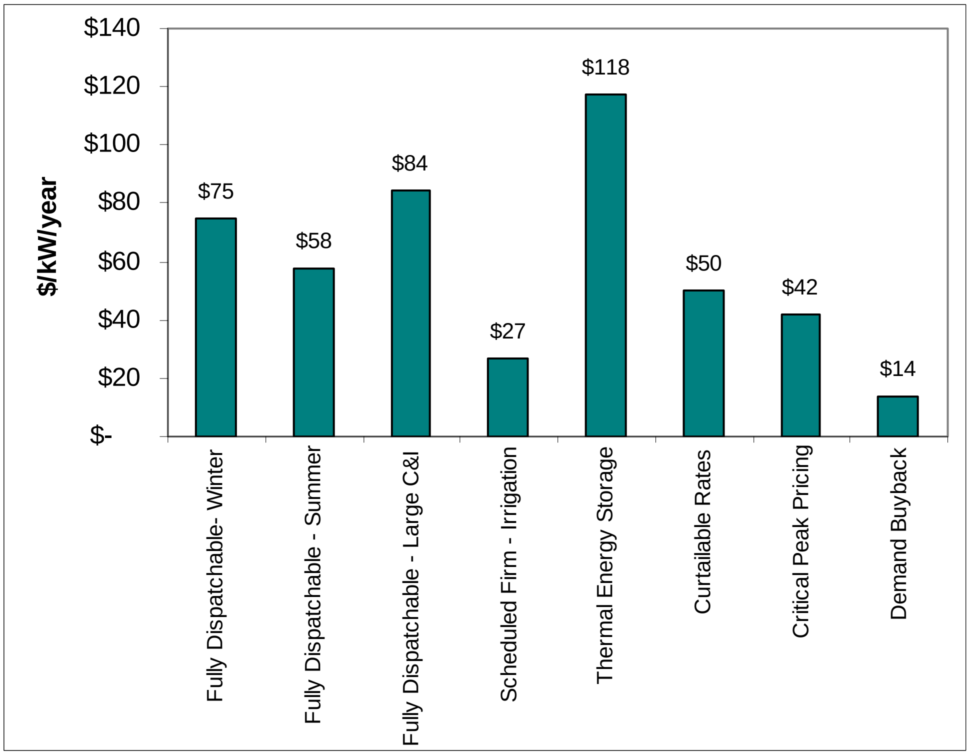


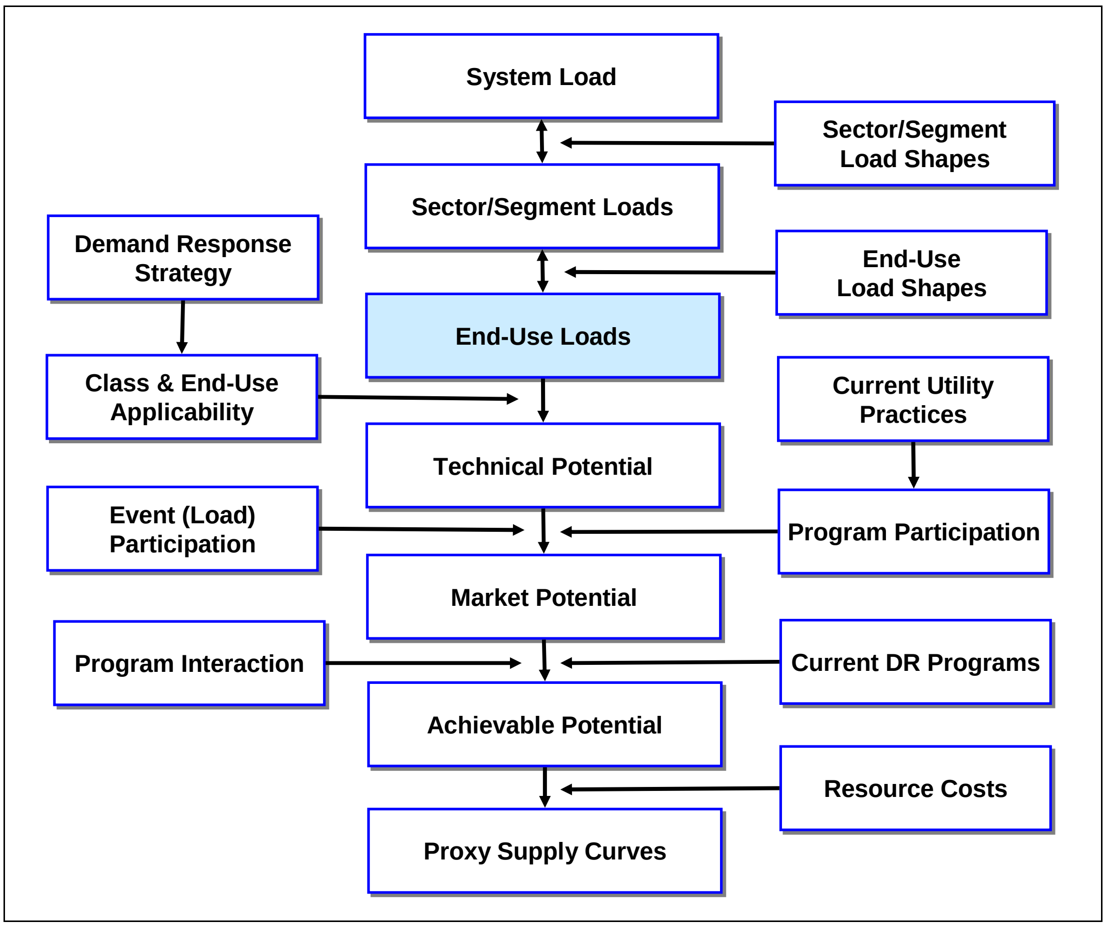
Table 6. Comparison of Costs with and without Metering Costs

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
With Meter Costs ($/kW/year)	$76	$59	$84	$28	$118	$50	$49	$14
Without Meter Costs ($/kW/year)	$75	$58	$84	$27	$118	$50	$42	$14

IV. Methodology and Data

The development of proxy supply curves requires both reasonable approximations of available quantities and reliable estimates of procurement costs for each DR resource. With respect to quantities, the overall approach in this project (see Figure 6) distinguishes between three definitions of DR resource potential that are widely used in utility resource planning: *technical, market,* and *achievable.* Load shapes for the PacifiCorp system, East/West regions, customer segments, and end use load shapes combine with sales data to produce hourly load profiles. For each DR strategy, technical potential is estimated by applying end use and sector applicability, while market potential additionally incorporates program and event participation. Achievable potential estimates also consider interactions among programs and current DR offerings at PacifiCorp. Finally, proxy supply curves show the relationship between achievable potential and the expected per-unit cost of each strategy.

Figure 6. Schematic Overview of Methodology



Data Requirements and Sources

Development of DR supply curves requires the compilation of a large and complex database on load data, end-use and appliance saturations, demand response impacts, and costs, gathered from multiple sources. To the greatest extent possible, this study relies on data available from PacifiCorp on loads, sales, end-use load profiles, and estimates of administrative costs. Secondary data sources were utilized for estimates of DR program impacts. Specific data elements and their respective sources are listed in Table 7.

Table 7. Data Elements and Sources

Data Element	Source – Various Years
Total Sales by Customer Class	PacifiCorp, 2005, Table A
Commercial Segmentation	PacifiCorp, 2005, Commercial Survey (by participants)
Hourly System and Regional Load Profiles	PacifiCorp, 2005
End-Use Shares and Load Shapes	EIA, Commercial Buildings Energy Consumption Survey (CBECS) EIA, Residential Energy Consumption Survey (RECS) Northwest Power Planning Council PacifiCorp PGE Quantec Load Shape Library
Existing PacifiCorp Demand Response Programs	PacifiCorp studies, various years
Demand Response Impact Estimates	PacifiCorp, California Energy Commission, Peak Load Management Alliance (PLMA), Edison Electric Institute (EEI), Lawrence Berkeley National Laboratories (LBNL), Various RTO and Utility Reports, Department of Energy
Demand Response Program Costs	PacifiCorp, Other Utilities, Regional Transmission Organizations

Methodology for Estimating Technical Potential

Within the context of demand response, technical potential assumes that all applicable end-use loads, in all customer sectors, are at least partially available for curtailment, excepting those customer segments (e.g., hospitals) and end-uses (e.g., restaurant cooking loads) that clearly do not lend themselves to curtailment.

Demand response options are not equally applicable to or effective in all segments of the electricity consumer market, and their impacts tend to be end-use specific. In recognition of this fact, this methodology employs a “bottom-up” approach, which involves first breaking down system loads for each of PacifiCorp’s two control areas into sectors, market segments within each sector, and applicable end uses within each market segment. Demand response potentials are estimated at the end-use level and then aggregated to sector and system levels. This approach is implemented in four steps as follows.

1. ***Define customer sectors, market segments, and applicable end-uses***. The first step in the process involves defining appropriate sectors and market segments within each sector. Given the available data, this study includes four customer classes (residential, commercial, industrial, and irrigation), the eleven commercial segments defined in

Commercial Building Energy Consumption Survey (Education, Food Stores, Hospitals, Hotels/Motels, Other Health, Offices, Public Assembly, Restaurants, Retail, Warehouses, and Miscellaneous), and total industrial loads.

2. ***Create sector and segment load profiles***. Using available local hourly load profiles, service area sales are used to generate sector- and segment-specific load shapes. Figure 7 displays the load duration curves for East, West and System overall, and Figure 8 shows the typical daily system load profiles. Figure 9 exhibits sector load shapes; the "System" shown is the actual load and "Total Sector" is the sum of load by sector. The difference between these lines are due to loads that are not amenable to demand response, such as traffic and street lighting, and loads not directly attributable to end use load profiles.

Figure 7: PacifiCorp Load Duration Curve, 2005

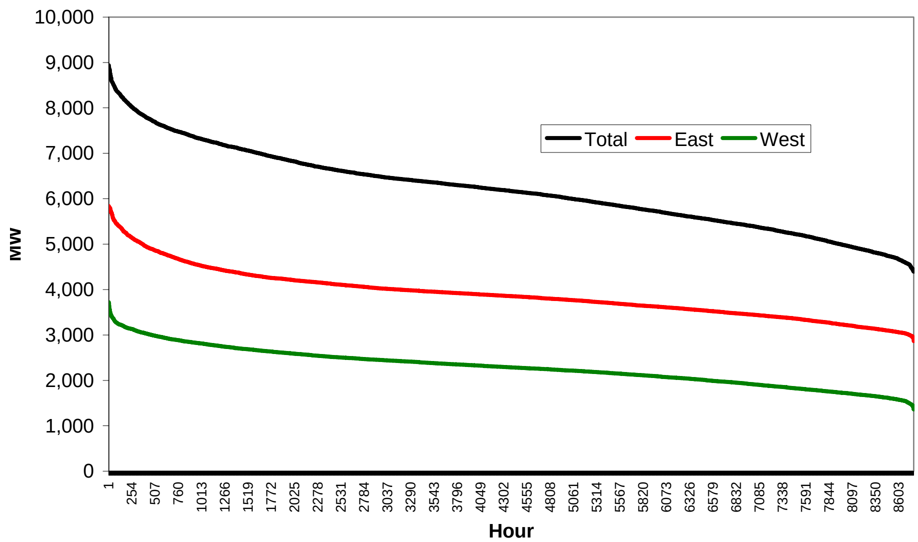


Figure 8: Typical Daily (Week-Day) Seasonal Load Profiles by System and Control Area

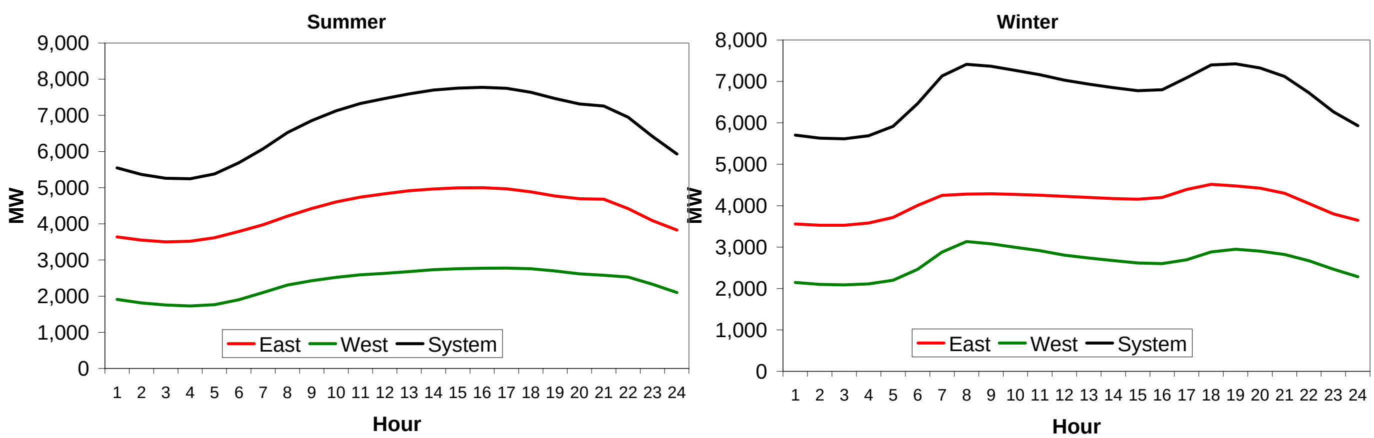
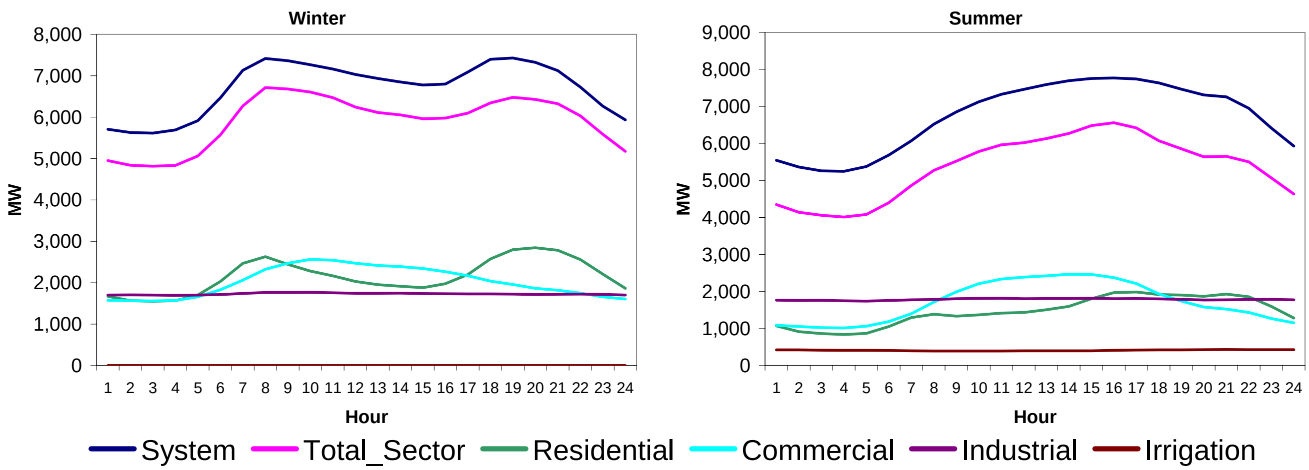


Figure 9: Typical Daily (Week-Day) System Load Profiles by Sector



3. ***Develop sector- and segment-specific typical peak day load profiles for each end use.*** "Typical" daily profiles are developed for each end-use within various market segments. Contributions to system peak for each end-use are estimated based on end-use shares available from PacifiCorp or regional estimates, available through EIA energy use surveys. Figure 10 and Figure 11 display the end-use contributions, summarized across sectors, to system load.

Figure 10: End-Use Contributions to System Load- Summer

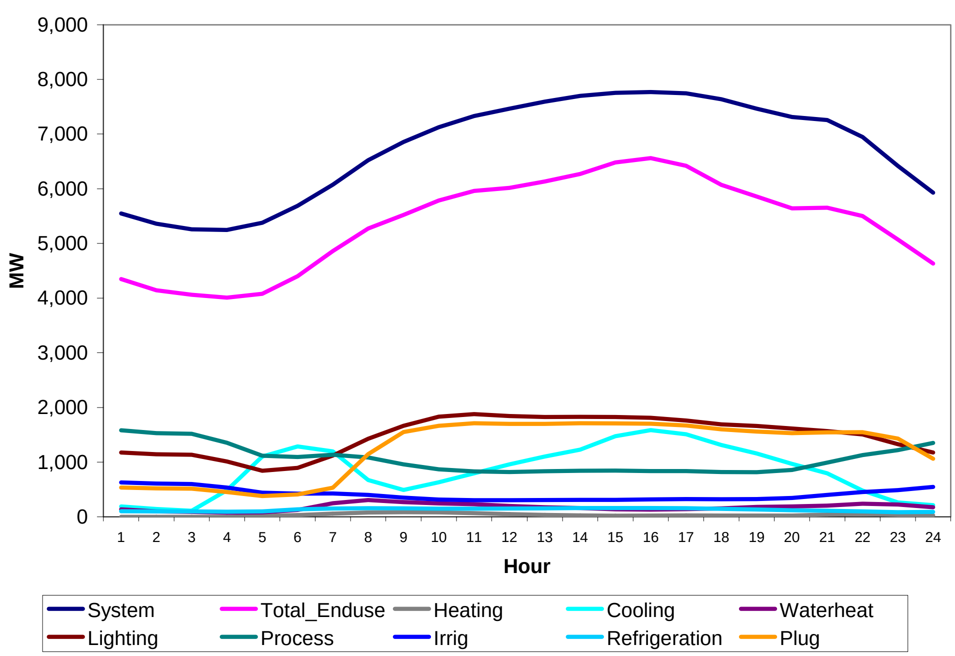
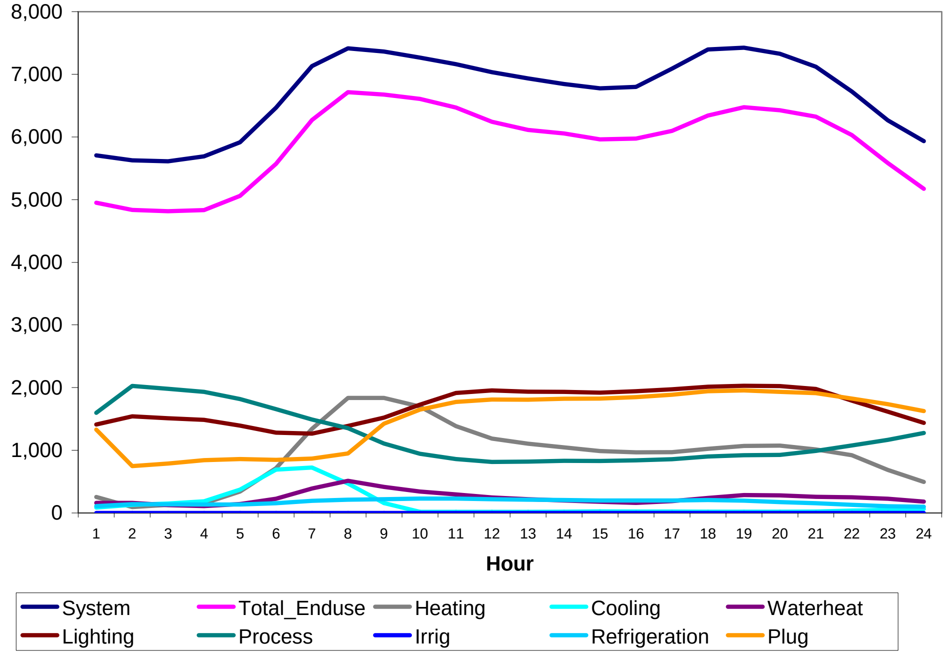


Figure 11: End-Use Contributions to System Load- Winter



4. ***Estimate technical potential***. Technical potential for each demand response strategy is assumed to be a function of customer eligibility in each class and the expected impact of the strategy on the targeted end-uses. Analytically, technical potential (*TP*) for demand-response strategy *s* is calculated as the sum of impacts at the end-use level (*e*), generated in customer sector (*c*), by the strategy (*s*), that is:

$$TP_s = \sum TP_{sce}$$

and

$$TP_{sce} = LE_{cs} \times LI_{se}$$

where,

- LE_{cs} (load eligibility) represents the percent of customer class loads that are eligible for strategy *s*
- LI_{se} (load impact) is percent reduction in end-use load *e* resulting from strategy *s*

Load eligibility (LE_{cs}) thresholds are established by calculating the percent of load by customer class and market segment that meet load criteria for each strategy. Table 8 outlines the portion of load that is eligible for program strategies. (Section V provides detailed program-specific assumptions.)

Estimates of maximum load impacts, resulting from various demand response strategies (LI_{se}), are derived from the commercial and industrial Enhanced Automation Study sponsored by the California Energy Commission, studies by Lawrence Berkeley National Laboratories (e.g., Goldman, 2004), and the experiences of PacifiCorp and other utilities with similar DR programs. Table 9 outlines these inputs; detailed assumptions are found in the following section.

Table 8: Eligibility by Sector and Program

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	100%	100%	- - -	- - -	- - -	-	100%	-
Education	- - -	- - -	19%	- - -	- - -	50%	100%	50%
Food Stores	- - -	- - -	27%	- - -	- - -	70%	100%	70%
Hospitals	- - -	- - -	- - -	- - -	- - -	-	-	-
Hotels/Motels	- - -	20%	5%	- - -	20%	12%	100%	12%
Other Health	- - -	7%	23%	- - -	7%	60%	-	60%
Miscellaneous	- - -	- - -	- - -	- - -	- - -	-	-	-
Offices	- - -	10%	19%	- - -	10%	50%	100%	50%
Assembly	- - -	10%	8%	- - -	10%	20%	-	20%
Restaurants	- - -	50%	- - -	- - -	50%	-	-	-
Retail	- - -	12%	- - -	- - -	12%	-	-	-
Warehouses	- - -	13%	15%	- - -	13%	40%	-	40%
Industrial	- - -	- - -	30%	- - -	- - -	80%	100%	80%
Irrigation	- - -	- - -	19%	100%	- - -	50%	-	-
Eligibility Criteria	Residential	Residential and Small Commercial (<30 kW)	Large C&I - >250 kW with EMS	Irrigation only	Small Commercial	Large C&I - >250 kW	No Load Threshold	Large C&I - >250 kW

Table 9: Technical Load Impacts

Program Name/Sector	Fully Dispatchable				Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter		Summer	Large C&I					
End Use	Space Htg	Hot Water	Cooling	Total	Process	Cooling	Total	Total	Total
Residential	90%	90%	90%	- - -	- - -	- - -	- - -	25%	- - -
Education	- - -	- - -	- - -	22%	- - -	- - -	22%	25%	22%
Food Stores	- - -	- - -	- - -	20%	- - -	- - -	20%	25%	20%
Hospitals	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Hotels/Motels	- - -	- - -	90%	20%	- - -	90%	20%	25%	20%
Other Health	- - -	- - -	90%	8%	- - -	90%	8%	- - -	8%
Miscellaneous	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Offices	- - -	- - -	90%	32%	- - -	90%	32%	25%	32%
Assembly	- - -	- - -	90%	20%	- - -	90%	20%	- - -	20%
Restaurants	- - -	- - -	90%	- - -	- - -	90%	- - -	- - -	- - -
Retail	- - -	- - -	90%	- - -	- - -	90%	- - -	- - -	- - -
Warehouses	- - -	- - -	90%	30%	- - -	90%	30%	- - -	30%
Industrial	- - -	- - -	- - -	30%	- - -	- - -	30%	25%	30%
Irrigation	- - -	- - -	- - -	30%	90%	- - -	30%	- - -	30%

Methodology for Estimating Market Potential

Market potential is the subset of technical potential that may reasonably be implemented, taking into account the customers' ability and willingness to participate in load reduction programs, subject to their unique business priorities, operating requirements, and economic (price) considerations. Market levels of potential are derived by adjusting technical potentials by two factors: expected rates of *program* and *event* participation. Market potential (*MP*) is calculated as the product of technical potential, sector program participation rates (PP_c), and expected event participation (EP_c) rates:

$$MP_s = TP_{sc} \times PP_c \times EP_c$$

Rates of program and event participation are estimated based on the recent experiences of PacifiCorp and other utilities, as well as those of Regional Transmission Organizations (RTOs) that have offered similar programs. Table 10 outlines the estimates of program and event participation; referenced assumptions are found Section V.

Table 10: Program and Event Participation Inputs

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Program Participation	10%	20%*	3%	50%	20%	25%	3%	35%
Event Participation	100%	100%	90%	50%	100%	90%	90%	13%

* Represents residential sector; commercial sector is assumed to be 5%

Utility customers' willingness to participate in DR programs (or "market potential") is itself a function of price and non-price factors. Non-price factors generally depend on specific operational constraints that may impede participation in DR. These are generally difficult to quantify and may only be determined through rigorous market studies.

Price-induced effects, particularly for market-based DR strategies, can, however, be estimated explicitly by calculating price elasticity of load response, based on empirical data, using the following general formulation of price elasticity:

$$LogN(MW) = \alpha + \beta \,\mathrm{LOG}(P),$$

where *MW* is the quantity of demand reduction commitment during each curtailment event and *P* represents the offer prices (incentives) from the utility.

Since the equation is specified in logarithmic form, β is a direct measure of elasticity, indicating percent change in load commitment that may be expected to result from a one percent change in incentives.

To estimate the parameters of the above model, data were collected on the 2000-2001 experience of four major utilities in the Northwest (PacifiCorp, PSE, PGE, and Avista) on their demand buyback programs. The estimated parameters of the model are shown below.

$$LogN(MW) = -0.5 + 1.45\ (3.0)\ \mathrm{LogN}(P)$$

The calibration of the demand model resulted in a price coefficient of 1.45 with a t-statistic of 3.0, indicating that the estimated coefficient is statistically significant at the 95% level of significance or better. The estimated parameter for the price variable shows that for every one percent change in price, load response is expected to change by 1.45%, indicating a moderately elastic response. The statistical parameters of the estimated model are shown in Table 11, below.

Table 11. Estimation Results of the Elasticity Model

Variable	Estimated Parameter	t-Statistic
Intercept (α)	-0.5	
LogN (Price)	1.45	3.0
Number of Observations: 13		

$R^2 = 0.65$

The elasticity estimate obtained from the data is higher than expected. There have not, however, been any other studies of response elasticity for demand buyback or demand biding programs. Additionally, slight changes in the specification of the above quantity/price relationship, introduced by using alternative data frequency levels, such as daily or monthly, are likely to alter the parameter estimates. For example, daily, event-by-event data, available from Puget Sound Energy for 2000-2001, resulted in a significantly lower elasticity of 0.45. Unfortunately, event-by-event data were not available for all four utilities. Such data, we expect, would likely have produced a more robust and reliable estimate of price elasticity for demand buyback programs.

Development of Cost Estimates

Demand response strategies vary significantly with respect to both type and level of costs. Applicable resource acquisition costs for DR generally fall into two categories: 1) fixed direct expenses such as infrastructure, administration, and data acquisition; and 2) variable costs (i.e., incentive payments to participants). For this project, cost estimates are based on the experiences of PacifiCorp and other utilities, as well as RTOs offering various DR programs.

Fixed Costs. Fixed costs vary significantly across various DR resource acquisition programs and depend, to a large extent, on program design. For example, implementation of some market-based programs, such as demand buyback, may require up-front investments in communication and data acquisition infrastructures, while tariff-based programs may be implemented at a relatively low cost to the utility.

Variable Costs. Estimation and treatment of variable costs, particularly in the case of market-based programs poses a much greater challenge in determining the price component of the supply curve as, clearly, these will have a direct effect on the quantity of resources that are available. As described above, elasticity estimates were used to account for these impacts.

Table 12 outlines the development (up-front investment) and annual costs for the three categories of cost inputs: per-kW/year, per-customer, and program administration. Incentive payments for large commercial and industrial customers are often paid on a per-kW basis. On a per-customer basis, development costs typically include control hardware, installation, and marketing costs; annual costs include maintenance and incentives. Program costs were assumed to be relatively consistent across all programs - $300,000 to begin a new program, $150,000 to expand existing programs[10]; $100,000 in ongoing administrative cost.[11]

Table 12: Cost Inputs

Cost Type/ Frequency	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
per kW-year								
Development	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Annual	- - -	- - -	$48	$10	$105	$48	- - -	$10
per Customer-year (including meter costs)								
Development	$320	$320	$1,200	$700	- - -	$1,200	$500	$700
Annual	$112	$55	- - -	$1,000	- - -	- - -	$50	- - -
Program								
Development	$300,000	$150,000	$300,000	$150,000	$300,000	$300,000	$300,000	$150,000
Annual	$100,000	$100,000	$100,000	$600,000	$100,000	$100,000	$100,000	$100,000

These costs are allocated to each year of the planning horizon, based on:

$$Costs_{sy} = \$Pgm_{dy1} + \$Pgm_{a} + (\$kW_{a} \times kW_{y}) + (\$Customer_{d} \times Part_{y-y0}) + (\$Customer_{a} \times Part_{y})$$

10 PacifiCorp Energy Exchange (2001) spent over $200,000 in initial costs. TOU (2001) had initial costs of $341,000, including load research.

11 Energy Exchange (2005) spends $72,000 annually in external vendor costs (not including PacifiCorp administrative costs), Idaho Irrigation Pilot (2005) spent $55,000 in program management, TOU had ongoing costs of $155,000 (2002) and $110,000 (2003).

Where,

- $Costs_{sy}$ are the costs for a program strategy *s* in year *y,*
- $\$Pgm_{dy1}$ are the program development costs in year 1 only
- $\$Pgm_{a}$ are the annual program costs
- *$kWa* are the annual costs on a per kW basis (Table 12)
- kW_y is the amount of kW potential in year *y*. This study uses a three-year ramping, such that one-third of the achievable potential, shown in Table 4, is added in each of the first three program years. The quantity in subsequent years increases at the same rate as sales.
- $\$Customer_d$ are per-customer development costs
- $Part_{y-y0}$ is the number of new participants in the program in year y
- $\$Customer_a$ is the annual cost per customer
- $Part_y$ is the number of total participants in the program, as a function of PartkW, which is the kW impact per customer, as shown in Table 13 (program-level assumptions found in Section V).

$$Part_y = \frac{kW_y}{Part_{kW}}$$

Table 13: Load Impact per Customer (kW)

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	2.0	1.5	---	---	---	---	2	---
Education	---	---	124	---	---	124	21	124
Food Stores	---	---	134	---	---	134	22	134
Hospitals	---	---	---	---	---	---	-	---
Hotels/Motels	---	2.0	104	---	---	104	10	104
Other Health	---	2.0	82	---	---	82	---	82
Miscellaneous	---	---	---	---	---	---	---	---
Offices	---	2.0	221	---	---	221	7	221
Assembly	---	2.0	230	---	---	230	---	230
Restaurants	---	2.0	---	---	---	---	---	---
Retail	---	2.0	---	---	---	---	---	---
Warehouses	---	2.0	173	---	---	173	---	173
Industrial	---	---	531	---	---	531	53	531
Irrigation	---	---	---	90	---	---	---	---

Resource Interaction Estimates

The final step in supply curve development is to estimate the amount of market potential that is available for each program in the portfolio. Table 14 outlines the percent of market potential that is considered available, given the ranking of programs by levelized cost with consideration given to reliability. For example, 100% of demand buyback and scheduled firm irrigation is considered achievable. Although critical peak pricing is ranked next in levelized cost, it is another non-firm resource, so it becomes tertiary to curtailable rates. Curtailable rates and dispatchable large C&I compete for the same target market as DBB, therefore only 50% of their market potential will be available. The summer DLC program is the least expensive residential and small commercial control program. Therefore 100% of this program is available. Since the TES also targets the cooling loads (cool storage) as a secondary option, half of the TES potentials are assumed to be available.

Table 14: Interaction (Percent of Market Potential Available)

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	50%	100%	- - -	- - -	- - -	- - -	20%	- - -
Education	- - -	- - -	50%	- - -	- - -	50%	20%	100%
Food Stores	- - -	- - -	50%	- - -	- - -	50%	20%	100%
Hospitals	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Hotels/Motels	- - -	100%	50%	- - -	50%	50%	20%	100%
Other Health	- - -	100%	50%	- - -	50%	50%	- - -	100%
Miscellaneous	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Offices	- - -	100%	50%	- - -	50%	50%	20%	100%
Assembly	- - -	100%	50%	- - -	50%	50%	- - -	100%
Restaurants	- - -	100%	- - -	- - -	50%	- - -	- - -	- - -
Retail	- - -	100%	- - -	- - -	50%	- - -	- - -	- - -
Warehouses	- - -	100%	50%	- - -	50%	50%	- - -	100%
Industrial	- - -	- - -	50%	- - -	- - -	50%	20%	100%
Irrigation	- - -	- - -	50%	100%	- - -	50%	- - -	- - -

V. Detailed Program Assumptions

Table 15. Fully Dispatchable – Winter

Programs Researched	Portland General Electric Space and Water Heating Direct Load Control Program; Pennsylvania, New Jersey, Maryland ISO water heating; Florida Power & Light Residential On Call program; Puget Sound Energy Home Comfort Control Thermostat; Hawaiian Electric Residential Hot Water; Wisconsin Public Services DLC
Load Basis	Average of top 87 winter hours
Basis for Cost Calculations	Development: Customer - $300 for control equipment and labor, $200 for meter and installation labor (PGE – Quantec 2003) but installed for only 10% of participants, $300,000 for program development; Annual: $30 in maintenance, $9 (1.5/month for 6 months) in communications, $72 ($12/month for 6 months - both water heating and space) in incentives, and $100,000 annual program administration.
High/Low Cost Notes	High assumes incentives are increased ($15/month - $90), low is half incentive ($6/mth - $36). Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Less than complete technical ability to cycle different technologies (90%) and 50% cycling strategy; therefore 45%
Eligible Load (%)	Residential space heating and water heating
Program Participation (%)	High is based on 20% participation of FPL On Call program, base (10%) closer to Duke program of 13% (Duke – Quantec 2005), and low (5%) represents low program participation (DOE - 2006)
Event Participation (%)	100%
Current Program (kW)	NA
Per-Customer Impacts (kW)	2kW estimate per participant based (PSE, Quantec 2003) - includes cycling strategy
Hours Per Month	3 hours in January; 84 hours in December (based on the distribution of the PacifiCorp 2005 system profile)

Table 16. Fully Dispatchable – Summer

Programs Researched	Florida Power & Light Residential On Call & Business On Call; SCE Large Business Summer Discount Plan; Wisconsin Public Services; Duke Residential AC Program, PacifiCorp and MidAmerican
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Customer - $300 for control equipment and labor, $200 for meter and installation labor (PGE – Quantec 2003) but installed for only 10% of participants, $300,000 for program development; Annual: $30 in maintenance, $4.5 (1.5/month for 3 months) in communications, incentives - $20 (3 months at $7/month - PSE pays $6, Duke $8, PAC $7), and $100,000 annual program administration
High/Low Cost Notes	High assumes incentives are doubled ($40), low is half incentive ($10). Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Less than complete technical ability to cycle different technologies (90%) and 50% cycling strategy; therefore 45%
Eligible Load (%)	Cooling load for residential and portion of commercial load that is less than 30 kW (PacifiCorp - Quantec 2003)
Program Participation (%)	Assumes 20% residential and 5% small commercial (FP&L - 13% small C&I participation, 19% residential, PAC Utah Cool Keeper 27% residential and ~0% commercial), high assumes that 5% more program participation is possible, low assumes 5% less
Event Participation (%)	100%
Current Program (kW)	65 MW of load reduction in Utah Cool Keeper Program on Dispatch mode
Per-Customer Impacts (kW)	Impact: Cooling - 1.5 kW for residential, 2.0 kW for small com, DOE 2006, Quantec 2003
Hours Per Month	June 8, July 54; August 32 – adjusts 2005 System load to account for experience in program dispatch by Cool Keeper

Table 17. Fully Dispatchable – Large C&I

Programs Researched	Florida Light & Power C&I On Call; Hawaiian Electric Large Commercial; Wisconsin Public Services DLC; Southern California Edison Large Business Summer Discount Plan
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Per customer of $500 for targeted marketing and $700 for meter (Duke – Quantec 2005); $300,000 for program development, $100,000 annual program administration. Per kW costs assume $8/month for 3 months (double the incentive as curtailable rates but for fewer months)
High/Low Cost Notes	High incentive is $14/month and low is $6/month (again, double curtailable rates incentive; see curtailable rates for references) Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of cooling load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003) and assuming only 38% with EMS systems (CBSA 05)
Program Participation (%)	Participation - Florida Power And Light C&I On Call has less than 1% of all customers. Because our figures already account for those not eligible, we have assumed 3% base, 8% high, and 1% low.
Event Participation (%)	90%
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	June 8, July 54; August 32 - adjusts 2005 System load to account for experience in program dispatch by Cool Keeper, assuming that system decisions to curtail residential customers would be similar for C&I customers

Table 18. Scheduled Firm – Irrigation

Programs Researched	BPA Irrigation, Idaho Power, PacifiCorp
Load Basis	Average of entire summer on-peak period
Basis for Cost Calculations	Development: $700 installed cost of advanced metering technologies; Idaho IRR: Annual: $10 per kW ($8.5 in 2005), $300,000 for program development, $100,000 annual program administration. Also includes $500K of additional expenditures committed in 2005 for ongoing programs by PacifiCorp.
High/Low Cost Notes	High cost doubles incentive; low assumes the same, Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Less than complete technical ability to schedule reductions on all load (e.g., lift stations)
Eligible Load (%)	Irrigation sector
Program Participation (%)	Program participation of 50% (2005 Idaho IRR - 100 MW signed up of 200 MW load) is assumed to be base. High and low has relatively tight band +/-5%.
Event Participation (%)	50% event participation assumes participants sign up only for 2 out of 4 days (similar to PacifiCorp Idaho program)
Current Program (kW)	48 MW from Idaho program
Per-Customer Impacts (kW)	Idaho reduction of 100 kW per customer reduced to 90 to account for smaller irrigators in other regions
Interaction	100% taken due to relatively inexpensive cost and lack of competition with other programs.
Variable Cost $/MWh	NA
Hours Per Month	June – August 96 hours per month, September 48 hours per month (4 days per week, 6 hours per day)

Table 19. Thermal Energy Storage

Programs Researched	Based on RFP response to PacifiCorp, summarized for Quantec in "TES Overview"
Load Basis	Average of entire summer on-peak period
Basis for Cost Calculations	Costs from "TES Overview" sent to Quantec on June 2, 2006 using per-kW costs by external vendor, $300,000 for program development, $100,000 annual program administration
High/Low Cost Notes	Incentives remain constant, Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Less than complete technical ability to use this technology (90%) on cooling load
Eligible Load (%)	Using portion of commercial cooling load that is less than 30 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	20% program participation, with +/- 5% for high and low participation
Event Participation (%)	100%
Current Program (kW)	NA
Per-Customer Impacts (kW)	NA
Hours Per Month	240 – April, 186 – May, 180 – June, 186 – July, 186 – August, 180 – September, 279 October

Table 20. Curtailable Rates

Programs Researched	Duke Interruptible Power Service; Georgia Power (Southern) Demand Plus Energy Credit; Duke Curtailable Service Pilot; Dominion Virginia Power Curtailable Service; MidAmerican; ConEd Interruptible/Curtailment Service, Southern California Edison C&I Base Interruptible Program, Wisconsin
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Per Customer of $500 for marketing and $700 for meter (Duke - Quantec, 05); $300,000 for new program development, $100,000 annual program administration, Base incentive of $48 ($4/kWMonth) (Pacific Gas and Electric pays $3-$7/kWMonth, Southern California Edison pays $7/kWMonth, Wisconsin Power and Light pays $3.3/kWMonth, MidAmerican pays $3.3, Duke Power pays $3.5/kW-Month).
High/Low Cost Notes	Base incentive of $48 ($4/kWMonth) is increased by 50% in high case. Low assumes same incentive as base ($42). Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	National participation ranges from slightly greater than 0% (ISO NE) of customers to 30%, (NYISO 29%, Duke 14%). Base assumes 25% (due to load eligibility already accounted for), 5% more for high case and 12.5% less for low case.
Event Participation (%)	Event Participation reflects compliance rate (Duke - 90% + compliance, CEC – 90% + compliance Goldman (2002))
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 69; August 18 (based on the distribution of the PacifiCorp 2005 system profile)

Table 21. Critical Peak Pricing

Programs Researched	Gulf Power GoodCents Select; Pacific Gas and Electric Critical Peak Pricing; Southern California Edison Critical Peak Pricing; San Diego Gas and Electric Critical Peak Pricing
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Customer: $500 for advanced metering technologies; Program - $300,000 for new program development; Annual: Customer - $20 for meter reading, extra mailing, and messaging (PSE – Quantec (2004)), $30 to account for the rate and energy benefits to the customer (Quantec PacifiCorp TOU (2005)) $100,000 annual program administration
High/Low Cost Notes	Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Range of impacts from high 41% (Gulf Power super peak) to 18% (Piette, 2006), therefore assume low-mid-point of 25%, (other relevant references – McAulife (2004) DOE 2006)
Eligible Load (%)	Eligibility- all customers assumed to be eligible except those deemed unable to respond (based on sectors reported in Quantum (2004))
Program Participation (%)	Current programs in nation have very low participation (reviewed seven programs McAulife (2004) and Gulf Power with maximum of 3% - PG&E commercial program) - base is 3%, low is 0.5% and high is 5.5%
Event Participation (%)	Event participation assumed to be less than all - i.e., 90%
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 69; August 18 (based on the distribution of the PacifiCorp 2005 system profile)

Table 22. Demand Buyback

Programs Researched	Pacific Gas and Electric Demand Buyback (Commercial and Industrial); Southern California Edison Demand Buyback (Commercial and Industrial); San Diego Gas and Electric Demand Buyback; New York ISO Day Ahead Demand Response, PacifiCorp
Load Basis	Average of top 175 summer hours
Basis for Cost Calculations	Development: $700 for advanced meter; Program development cost of $150,000 for expansion; $100,000 annually for program administration. Incentive of $10/kW is consistent with 2005 PacifiCorp Integrated Resource Plan base prices of $60/MWh
High/Low Cost Notes	High and low incentive levels are consistent with 2005 PacifiCorp Integrated Resource Plan base prices of $40/MWh (low) and $100/MWh (high). Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	Range of program participation is from 0-6% (various California utilities – Quantum (2004)) to 17-25% (PJM/NYISO – Goldman (2004)). This study uses 35% to account for the eligibility correction for those >250 kW. High is 30%, low is 5%
Event Participation (%)	Event participation calculated from 2001 Northwest demand bidding experience
Current Program (kW)	1 MW of participation (165 MWh over 15 events, 10 hours per event)
Per-Customer Impacts (kW)	Per-customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 129; August 46 (based on the distribution of the PacifiCorp 2005 system profile)

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Appendix A: East Region Results

Table 23: Technical Potential (MW), East

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	143	- - -	- - -	377	392	368
Commercial	- - -	35	30	- - -	59	79	134	76
Irrigation	- - -	- - -	- - -	254	- - -	- - -	- - -	- - -
Residential	163	318	- - -	- - -	- - -	- - -	342	- - -
Total	*163*	*353*	*173*	*254*	*59*	*455*	*868*	*444*
% of East Peak	*3%*	*7%*	*3%*	*5%*	*1%*	*9%*	*17%*	*9%*

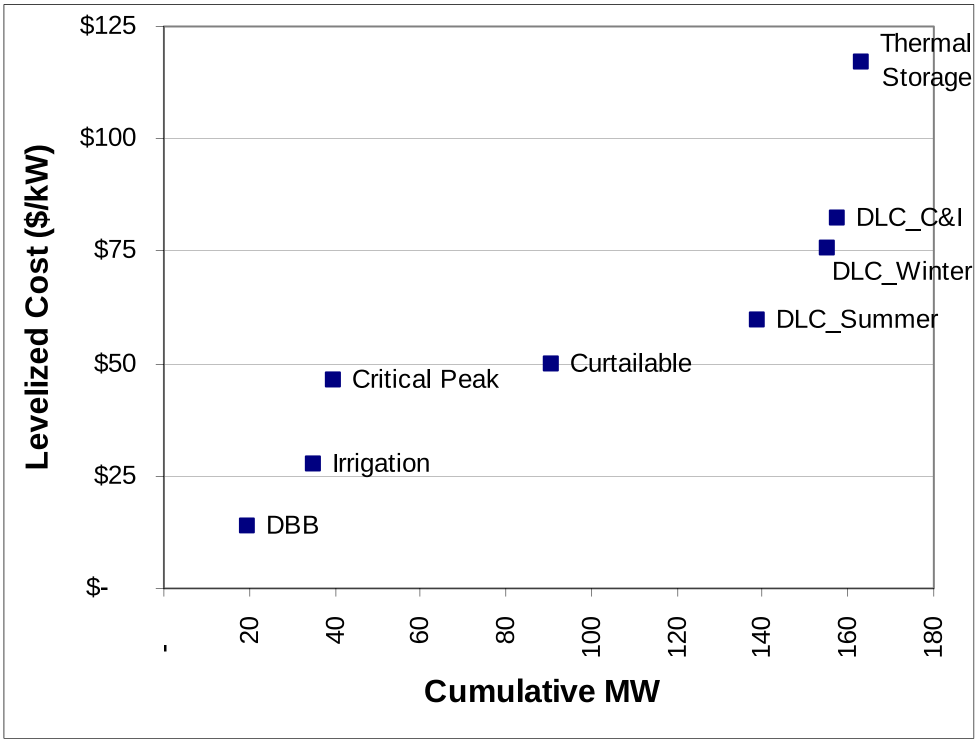
Table 24: Market Potential (MW), East

Sector	Fully Dispatchable			Scheduled Firm – Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	4	- - -	- - -	85	11	16
Commercial	- - -	2	1	- - -	12	18	4	3
Irrigation	- - -	- - -	- - -	63	- - -	- - -	- - -	- - -
Residential	33	111	- - -	- - -	- - -	- - -	9	- - -
Total	*33*	*113*	*5*	*63*	*12*	*102*	*23*	*19*
% of East Peak	*0.7%*	*2.3%*	*0.1%*	*1.3%*	*0.2%*	*2.0%*	*0.5%*	*0.4%*

Table 25. Achievable Potential (MW) and Costs, East

	Fully Dispatchable			Scheduled Firm – Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Resource Costs ($/kW/yr)	$76	$59	$82	$28	$117	$50	$46	$14	- - -
Achievable Potential	16	113	2	63	6	51	5	19	276
Potential Net of Current Programs	16	48	2	15	6	51	5	19	163

Figure 12: Cumulative Supply Curve, East



Appendix B: West Region Results

Table 26. Technical Potential, West

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	50	- - -	- - -	133	138	132
Commercial	- - -	20	21	- - -	35	54	98	54
Irrigation	- - -	- - -	- - -	128	- - -	- - -	- - -	- - -
Residential	210	33	- - -	- - -	- - -	- - -	275	- - -
Total	*210*	*54*	*71*	*128*	*35*	*187*	*512*	*185*
% of West Peak	*7%*	*2%*	*2%*	*4%*	*1%*	*6%*	*16%*	*6%*

Table 27. Market Potential, West

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	1	- - -	- - -	30	4	6
Commercial	- - -	1	1	- - -	7	12	3	2
Irrigation	- - -	- - -	- - -	32	- - -	- - -	- - -	- - -
Residential	42	7	- - -	- - -	- - -	- - -	7	- - -
Total	42	8	2	32	7	42	14	8
% of West Peak	*1.3%*	*0.2%*	*0.1%*	*1.0%*	*0.2%*	*1.3%*	*0.4%*	*0.3%*

Table 28. Achievable Potential (MW) and Costs, West

	Fully Dispatchable			Scheduled Firm – Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Resource Costs ($/kW/yr)	$76	$58	$89	$29	$119	$50	$63	$15	- - -
Achievable Potential	21	8	1	32	3	21	3	8	97
Potential Net of Current Programs	21	8	1	32	3	21	3	7	96

Figure 13: Supply Curve, West

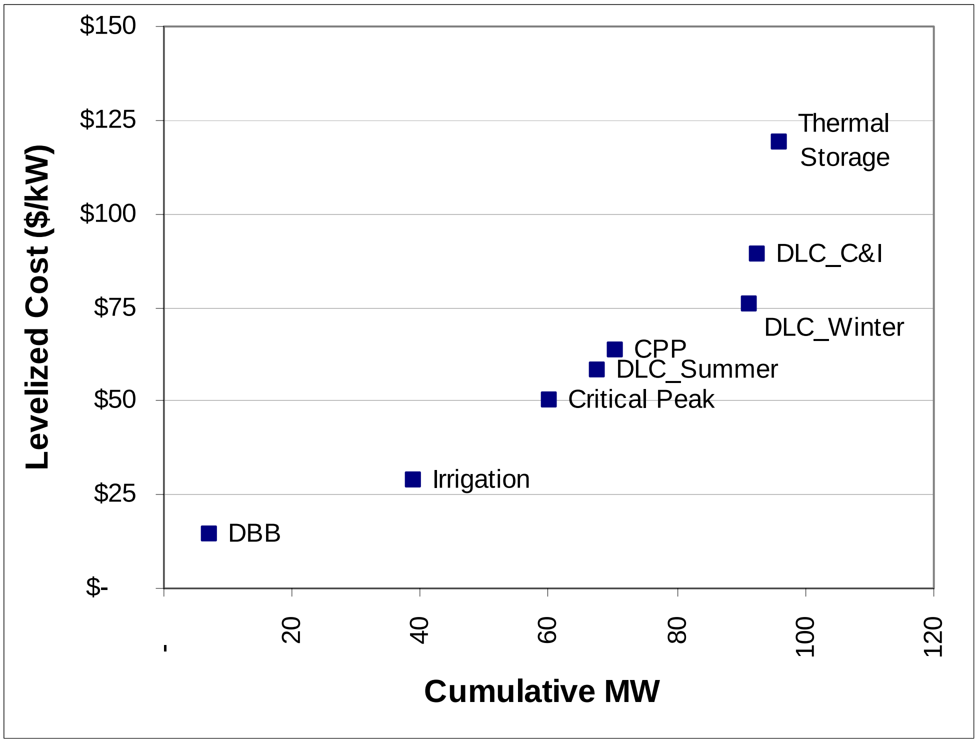


Figure 14: East Region, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	51	5	19
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 76	$ 59	$ 82	$ 28	$ 117	$ 50	$ 46	$ 14
Low								
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	22	1	6
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 58	$ 53	$ 159	$ 29	$ 115	$ 38	$ 95	$ 13
High								
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	63	9	46
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 84	$ 73	$ 101	$ 37	$ 118	$ 86	$ 42	$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 15: West Region, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	21	3	8
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 76	$ 58	$ 89	$ 29	$ 119	$ 50	$ 63	$ 15
Low								
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	9	0	3
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 58	$ 61	$ 185	$ 30	$ 116	$ 39	$ 144	$ 14
High								
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	26	5	19
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 84	$ 70	$ 104	$ 37	$ 121	$ 87	$ 56	$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 16: System, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	72	7	28
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 76	$ 59	$ 84	$ 28	$ 118	$ 50	$ 49	$ 14
Low								
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	30	1	9
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 58	$ 53	$ 167	$ 29	$ 115	$ 39	$ 91	$ 13
High								
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	88	14	65
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 84	$ 72	$ 102	$ 37	$ 119	$ 86	$ 45	$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 17: East Region, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	102	5
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 76	$ 59	$ 82	$ 28	$ 117	$ 49	$ 46
Low							
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	43	1
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 58	$ 53	$ 159	$ 29	$ 115	$ 37	$ 95
High							
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	125	9
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 84	$ 73	$ 101	$ 37	$ 118	$ 85	$ 42
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 18: West Region, No DBB

Program Name	Fully Dispatchable-Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	42	3
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs ($/kW/yr)	$ 76	$ 58	$ 89	$ 29	$ 119	$ 49	$ 63
Low							
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	18	0
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs ($/kW/yr)	$ 58	$ 61	$ 185	$ 30	$ 116	$ 38	$ 144
High							
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	51	5
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs ($/kW/yr)	$ 84	$ 70	$ 104	$ 37	$ 121	$ 86	$ 56
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 19: System, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	144	7
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 76	$ 59	$ 84	$ 28	$ 118	$ 49	$ 49
Low							
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	61	1
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 58	$ 53	$ 167	$ 29	$ 115	$ 37	$ 91
High							
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	177	14
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 84	$ 72	$ 102	$ 37	$ 119	$ 85	$ 45
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 20: East Region, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	51	5	19
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 75	$ 58	$ 82	$ 27	$ 117	$ 50	$ 40	$ 14
Low								
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	22	1	6
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 57	$ 52	$ 159	$ 28	$ 115	$ 38	$ 89	$ 13
High								
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	63	9	46
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 83	$ 71	$ 101	$ 36	$ 118	$ 86	$ 36	$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 21: West Region, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	21	3	8
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 75	$ 57	$ 89	$ 28	$ 119	$ 50	$ 56	$ 14
Low								
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	9	0	3
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 57	$ 60	$ 185	$ 29	$ 116	$ 39	$ 136	$ 14
High								
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	26	5	19
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 83	$ 69	$ 104	$ 37	$ 121	$ 86	$ 48	$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 22: System, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	72	7	28
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 75	$ 58	$ 84	$ 27	$ 118	$ 50	$ 42	$ 14
Low								
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	30	1	9
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 57	$ 52	$ 167	$ 29	$ 115	$ 38	$ 84	$ 13
High								
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	88	14	65
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 83	$ 71	$ 102	$ 36	$ 119	$ 86	$ 38	$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

APPENDIX C – DETAILED CEM MODELING RESULTS

This appendix presents detailed Capacity Expansion Module (CEM) results for the 16 alternative future scenarios, 16 sensitivity analysis scenarios, and an additional set of sensitivity scenarios requested by public stakeholders.

ALTERNATIVE FUTURE AND SENSITIVITY ANALYSIS SCENARIO RESULTS

Table C.1 – Alternative Future Scenarios

CAF #	Name	Coal Cost: CO_2 Adder/Coal Commodity Price	Gas/ Electric Price	Load Growth	Renewable Sales Percentage due to RPS	Renewable PTC Availability	DSM Potential
0	Business As Usual	None/Medium	Medium	Medium	Low	Yes	Medium
1	Low Cost Coal/High Cost Gas	None/Low	High	Medium	Medium	Yes	Medium
2	with Low Load Growth	None/Low	High	Low	Medium	Yes	Medium
3	with High Load Growth	None/Low	High	High	Medium	Yes	Medium
4	High Cost Coal/Low Cost Gas	High/High	Low	Medium	Medium	Yes	Medium
5	with Low Load Growth	High/High	Low	Low	Medium	Yes	Medium
6	with High Load Growth	High/High	Low	High	Medium	Yes	Medium
7	Favorable Wind Environment	High/Medium	High	Medium	High	Yes	Medium
8	Unfavorable Wind Environment	None/Medium	Low	Medium	Low	No	Medium
9	High DSM Potential	High/Medium	High	Medium	Medium	Yes	High
10	Low DSM Potential	None/Medium	Low	Medium	Medium	Yes	Low
11	Medium Load Growth	Medium/Medium	Medium	Medium	Medium	Yes	Medium
12	Low Load Growth	Medium/Medium	Medium	Low	Medium	Yes	Medium
13	High Load Growth	Medium/Medium	Medium	High	Medium	Yes	Medium
14	Low Cost Portfolio Bookend	None/Low	Low	Low	Medium	Yes	Medium
15	High Cost Portfolio Bookend	High/High	High	High	Medium	No	Medium

Table C.2 – Sensitivity Analysis Scenarios

SAS#	Name	Basis
1	Plan to 12% capacity reserve margin	CAF #11
2	Plan to 18% capacity reserve margin	CAF #11
3	CO_2 adder implementation in 2016	CAF #11
4	Regional transmission project	CAF #11
5-10 5-15 5-20	CO_2 adder impact on resource selection: test \$15, \$20, \$25 per ton adders (approximately \$10, \$15, and \$20 in 1990 dollars)	CAF #11
6	Low wind capital cost	CAF #11
7	High wind capital cost	CAF #11
8	Low coal price	CAF #11
9	High coal price	CAF #11
10	Low IGCC capital cost	CAF #11
11	High IGCC capital cost	CAF #11
12	Replace a baseload pulverized resource with carbon-capture-ready IGCC	CAF #11
13	Replace a baseload resource with IGCC/single gasifier	CAF #11
14	Replace a baseload resource with IGCC/sequestration	CAF #11
15	Plan to "average of super-peak" load	CAF #11
16	"Favorable Wind Environment" scenario assuming permanent expiration of the renewables PTC beginning in 2008	CAF07("Favorable Wind Environment")

In the following tables, fossil fuel resource additions are reported as nameplate megawatts accrued as of the year listed. Wind resources, unless noted otherwise, are reported as the estimated megawatt peak capacity contribution accrued as of the year listed.

Table C.3 – Aggregate Resource Additions

	PVRR	Resource Additions (MW)									
Scenario	(millions)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	$ 19,619	82	748	722	1,236	1,523	2,677	2,980	3,238	3,306	3,585
CAF01	$ 18,071	135	749	722	1,237	1,526	2,692	3,173	3,153	3,236	3,509
CAF02	$ 11,022	45	423	210	576	696	1,704	1,667	2,162	2,362	1,950
CAF03	$ 30,159	228	1,106	1,271	1,999	2,517	3,819	4,157	5,080	5,636	6,057
CAF04	$ 30,504	85	749	723	1,236	1,524	2,682	2,854	3,149	3,227	3,533
CAF05	$ 23,920	45	424	211	576	695	1,670	1,661	1,722	1,638	1,730
CAF06	$ 40,002	224	1,107	1,271	1,996	2,515	3,840	4,247	4,711	5,152	5,644
CAF07	$ 33,339	151	749	718	1,236	1,520	2,692	2,887	3,183	3,258	3,535
CAF08	$ 18,858	-	747	721	1,235	1,521	2,679	2,803	3,112	3,203	3,512
CAF09	$ 33,213	151	749	721	1,236	1,524	2,697	2,878	3,140	3,233	3,540
CAF10	$ 19,002	85	749	723	1,237	1,525	2,682	2,805	3,112	3,203	3,508
CAF11	$ 24,606	135	749	723	1,238	1,524	2,673	2,838	3,126	3,209	3,510
CAF12	$ 17,689	45	423	211	576	696	1,669	1,660	1,762	1,669	1,772
CAF13	$ 35,024	222	1,105	1,268	1,996	2,504	3,831	4,197	4,737	5,142	5,748
CAF14	$ 13,689	45	422	208	574	694	1,653	1,639	1,776	1,687	1,788
CAF15	$ 49,234	82	1,109	1,268	2,001	2,511	3,838	4,259	4,917	5,172	5,745
SAS01	$ 24,400	85	471	436	954	1,231	2,356	2,690	2,940	3,008	3,172
SAS02	$ 24,983	299	1,021	995	1,527	1,826	3,013	3,187	3,465	3,562	3,918
SAS03	$ 22,673	82	748	722	1,236	1,519	2,693	2,979	3,237	3,303	3,584
SAS04	$ 24,182	85	748	723	1,236	1,522	2,694	3,174	3,150	3,257	3,543
SAS05-10	$ 28,551	151	749	722	1,237	1,523	2,673	2,845	3,115	3,211	3,509
SAS05-15	$ 32,390	135	749	724	1,237	1,524	2,673	2,791	3,103	3,200	3,501
SAS05-20	$ 36,073	182	748	720	1,236	1,514	2,651	2,812	3,081	3,175	3,488
SAS06	$ 24,282	326	746	711	1,240	1,528	2,706	2,872	3,166	3,242	3,546
SAS07	$ 24,836	68	748	723	1,236	1,523	2,697	2,865	3,242	3,318	3,595
SAS08	$ 24,401	122	749	723	1,237	1,524	2,702	3,184	3,159	3,245	3,560
SAS09	$ 24,980	135	749	723	1,238	1,524	2,703	2,991	3,245	3,315	3,525
SAS10	$ 24,559	122	749	723	1,237	1,524	2,684	3,173	3,123	3,208	3,505
SAS11	$ 24,660	68	748	721	1,235	1,523	2,697	2,865	3,242	3,318	3,595
SAS12	$ 24,976	122	749	722	1,236	1,524	2,684	2,897	3,153	3,247	3,558
SAS13	$ 24,980	150	748	722	1,233	1,520	2,698	2,905	3,181	3,270	3,573
SAS14	$ 25,521	106	748	722	1,236	1,522	2,683	2,896	3,152	3,248	3,558
SAS15	$ 24,412	118	516	476	1,000	1,282	2,417	2,584	2,851	2,934	3,228
SAS16	$ 35,049	64	747	722	1,236	1,523	2,693	2,874	3,296	3,320	3,572

Table C.4 – Wind Resource Additions

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	300	300	300	300	300	300	300	300	300	300
CAF01	600	800	800	800	800	1,000	1,000	1,000	1,000	1,000
CAF02	200	400	400	400	400	400	400	400	400	400
CAF03	1,000	1,300	1,300	1,300	1,300	1,400	1,400	1,400	1,400	1,400
CAF04	400	400	400	400	400	400	500	500	500	1,400
CAF05	200	300	300	300	300	300	300	600	600	1,400
CAF06	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,500	1,800	2,200
CAF07	800	1,000	1,100	1,100	1,100	1,200	2,200	2,200	2,800	3,100
CAF08	-	-	-	-	-	-	-	-	-	-
CAF09	800	1,000	1,000	1,000	1,000	1,600	1,600	2,300	3,100	3,100
CAF10	400	400	400	400	400	400	400	400	400	400
CAF11	600	700	700	700	700	700	700	700	700	700
CAF12	200	300	300	300	300	400	400	400	400	400
CAF13	900	900	900	900	900	900	900	900	900	900
CAF14	200	300	400	400	400	400	400	400	400	400
CAF15	300	300	300	300	300	400	400	400	800	2,300
SAS01	400	500	500	500	500	600	600	600	600	600
SAS02	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,500	1,500
SAS03	300	400	400	400	400	400	400	400	400	400
SAS04	400	500	500	500	500	500	500	500	500	900
SAS05-10	800	900	900	900	900	900	1,100	1,100	1,200	1,200
SAS05-15	600	600	600	600	600	600	600	600	600	600
SAS05-20	1,100	1,200	1,200	1,200	1,200	1,900	1,900	1,900	1,900	2,800
SAS06	1,800	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
SAS07	300	300	300	300	300	300	400	400	400	500
SAS08	500	500	500	500	500	500	500	500	500	500
SAS09	600	700	700	700	700	700	700	700	700	700
SAS10	500	500	500	500	500	500	500	500	500	500
SAS11	300	400	400	400	400	400	400	400	400	400
SAS12	500	600	600	600	600	600	600	600	600	600
SAS13	600	700	700	700	700	700	700	700	700	700
SAS14	400	500	500	500	500	500	500	500	500	900
SAS15	600	700	700	700	700	800	900	900	900	900
SAS16	200	200	400	600	800	1,000	1,200	1,500	1,700	1,900

Table C.5 – Front Office Transactions

Figures shown are megawatts acquired in each year. Annual figures are not additive. Contract quantities were grossed up by the planning reserve margin to reflect the assumption that contract purchases are firm.

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	666	639	1,153	1,441	1,380	933	1,190	1,258	1,337
CAF01	-	599	573	1,088	1,377	1,380	1,111	591	674	197
CAF02	-	363	151	516	636	1,044	258	413	413	-
CAF03	-	848	988	1,697	2,133	1,380	219	444	492	116
CAF04	-	664	638	1,151	1,439	1,369	1,379	1,126	1,204	1,373
CAF05	-	355	143	507	627	1,378	1,369	1,380	1,296	1,291
CAF06	-	883	1,022	1,728	2,232	1,379	1,185	1,110	1,088	1,198
CAF07	-	583	515	1,033	1,317	1,363	1,380	726	758	973
CAF08	-	748	721	1,235	1,521	1,375	749	1,058	1,149	1,358
CAF09	-	583	555	1,071	1,358	1,380	811	805	765	1,072
CAF10	-	664	638	1,152	1,440	1,379	752	1,059	1,150	1,380
CAF11	-	601	575	1,090	1,377	1,379	1,380	919	1,002	1,303
CAF12	-	366	153	519	638	1,379	1,365	718	624	727
CAF13	-	883	1,045	1,755	1,961	1,355	1,366	1,156	811	909
CAF14	-	339	109	475	595	1,379	1,365	752	662	764
CAF15	-	1,027	1,160	1,874	2,083	1,380	1,051	459	649	987
SAS01	-	373	338	857	1,133	1,344	928	1,178	1,247	1,211
SAS02	-	722	696	1,228	893	1,408	1,415	1,352	1,416	1,022
SAS03	-	653	627	1,141	1,424	1,380	917	1,174	1,240	1,321
SAS04	-	651	626	1,139	1,425	1,379	1,109	1,084	1,191	1,380
SAS05-10	-	585	558	1,073	1,359	1,380	1,378	1,308	1,377	925
SAS05-15	-	614	589	1,102	1,389	1,302	1,379	941	1,038	1,339
SAS05-20	-	554	526	1,042	1,018	1,380	938	1,208	1,302	1,379
SAS06	-	406	370	899	1,188	1,370	1,380	923	999	1,304
SAS07	-	680	654	1,167	1,455	1,369	1,377	1,003	1,079	1,340
SAS08	-	627	600	1,114	1,402	1,380	1,112	1,087	1,173	1,148
SAS09	-	601	575	1,090	1,377	1,379	917	1,171	1,241	1,250
SAS10	-	627	600	1,114	1,402	1,380	1,119	1,068	1,153	1,251
SAS11	-	667	641	1,155	1,442	1,356	1,380	1,007	1,083	1,360
SAS12	-	614	588	1,102	1,381	1,380	843	1,099	1,194	1,304
SAS13	-	585	559	1,071	1,357	1,380	837	1,113	1,202	1,305
SAS14	-	630	604	1,118	1,404	1,380	843	1,099	1,195	1,380
SAS15	-	385	345	869	1,151	1,380	1,380	897	980	1,274
SAS16	-	683	613	1,080	1,334	1,372	782	413	413	649

Table C.6 – Gas Additions, Including Combined Heat & Power

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	-	-	-	-	125	125	125	125	125
CAF01	-	-	25	25	25	2,140	2,742	3,134	3,566	3,923
CAF02	-	-	-	-	-	100	100	100	100	100
CAF03	-	-	-	-	-	1,175	1,175	1,175	1,175	1,275
CAF04	-	-	-	-	-	-	-	-	-	-
CAF05	-	-	-	-	-	1,150	1,150	1,150	1,150	1,225
CAF06	-	-	-	-	-	734	759	759	759	759
CAF07	-	-	-	-	-	50	50	50	50	50
CAF08	-	-	-	-	302	1,628	1,628	1,628	1,628	1,628
CAF09	-	-	-	-	-	25	25	25	25	25
CAF10	-	-	25	25	327	1,211	1,211	1,211	1,211	1,211
CAF11	-	-	-	-	-	125	125	125	125	125
CAF12	-	-	-	-	634	634	734	734	734	734
CAF13	-	-	-	-	-	125	125	125	125	125
CAF14	-	-	-	-	-	125	125	125	125	125
CAF15	-	-	-	-	-	125	125	125	125	125
SAS01	-	-	25	25	25	2,140	2,742	3,134	3,566	3,923
SAS02	-	-	-	-	-	100	100	100	100	100
SAS03	-	-	-	-	-	1,175	1,175	1,175	1,175	1,275
SAS04	-	-	-	-	-	-	-	-	-	-
SAS05-10	-	-	-	-	-	979	1,029	1,029	1,029	1,029
SAS05-15	-	-	-	-	-	1,236	1,236	1,236	1,236	1,236
SAS05-20	-	-	-	-	302	759	1,361	1,361	1,361	1,361
SAS06	-	-	-	-	-	302	402	402	402	402
SAS07	-	-	-	-	-	634	684	684	684	684
SAS08	-	-	-	-	-	402	402	402	402	402
SAS09	-	-	-	-	-	427	427	427	427	427
SAS10	-	-	-	-	-	432	432	432	432	432
SAS11	-	-	-	-	-	634	659	659	659	659
SAS12	-	-	-	-	-	432	432	432	432	432
SAS13	-	-	-	-	-	402	402	402	402	402
SAS14	-	-	-	-	-	432	432	432	432	432
SAS15	-	-	-	-	-	407	457	457	457	457
SAS16	-	-	-	-	-	75	75	75	75	75

Table C.7 – IGCC Additions

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	-	-	-	-	-	-	-	-	200
CAF01	-	-	-	-	-	-	-	500	500	500
CAF02	-	-	-	-	-	-	-	-	200	200
CAF03	-	-	-	-	-	-	-	697	1,205	2,002
CAF04	-	-	-	-	-	-	-	-	-	-
CAF05	-	-	-	-	-	-	-	-	-	-
CAF06	-	-	-	-	-	-	-	-	-	-
CAF07	-	-	-	-	-	-	-	200	200	200
CAF08	-	-	-	-	-	-	-	-	-	-
CAF09	-	-	-	-	-	-	-	200	200	200
CAF10	-	-	-	-	-	-	-	-	-	-
CAF11	-	-	-	-	-	-	-	-	-	-
CAF12	-	-	-	-	-	-	-	-	-	-
CAF13	-	-	-	-	-	-	-	-	-	508
CAF14	-	-	-	-	-	-	-	-	-	-
CAF15	-	-	-	-	-	-	-	500	500	500
SAS01	-	-	-	-	-	-	-	-	-	200
SAS02	-	-	-	-	-	-	-	-	-	0
SAS03	-	-	-	-	-	-	-	-	-	200
SAS04	-	-	-	-	-	-	-	-	-	-
SAS05-10	-	-	-	-	-	-	-	-	-	-
SAS05-15	-	-	-	-	-	-	-	-	-	-
SAS05-20	-	-	-	-	-	-	-	-	-	-
SAS06	-	-	-	-	-	-	-	-	-	-
SAS07	-	-	-	-	-	-	-	-	-	-
SAS08	-	-	-	-	-	-	-	-	-	-
SAS09	-	-	-	-	-	-	-	-	-	200
SAS10	-	-	-	-	-	-	-	-	-	200
SAS11	-	-	-	-	-	-	-	-	-	0
SAS12	-	-	-	-	-	-	750	750	750	950
SAS13	-	-	-	-	-	-	750	750	750	950
SAS14	-	-	-	-	-	-	750	750	750	750
SAS15	-	-	-	-	-	-	-	-	-	-
SAS16	-	-	-	-	-	-	-	-	-	-

Table C.8 – Pulverized Coal Additions

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	-	-	-	-	940	1,690	1,690	1,690	1,690
CAF01	-	-	-	-	-	940	1,690	1,690	1,690	2,440
CAF02	-	-	-	-	-	600	1,350	1,690	1,690	1,690
CAF03	-	-	-	-	-	940	2,440	2,440	2,440	2,440
CAF04	-	-	-	-	-	-	-	-	-	-
CAF05	-	-	-	-	-	-	-	-	-	-
CAF06	-	-	-	-	-	-	-	-	-	-
CAF07	-	-	-	-	-	940	940	1,690	1,690	1,690
CAF08	-	-	-	-	-	-	750	750	750	750
CAF09	-	-	-	-	-	940	1,690	1,690	1,690	1,690
CAF10	-	-	-	-	-	-	750	750	750	750
CAF11	-	-	-	-	-	340	340	1,090	1,090	1,090
CAF12	-	-	-	-	-	-	-	750	750	750
CAF13	-	-	-	-	-	600	940	1,690	2,440	2,440
CAF14	-	-	-	-	-	-	-	750	750	750
CAF15	-	-	-	-	-	940	1,690	2,440	2,440	2,440
SAS01	-	-	-	-	-	600	1,350	1,350	1,350	1,350
SAS02	-	-	-	-	-	600	600	940	940	1,690
SAS03	-	-	-	-	-	940	1,690	1,690	1,690	1,690
SAS04	-	-	-	-	-	940	1,690	1,690	1,690	1,690
SAS05-10	-	-	-	-	-	-	-	340	340	1,090
SAS05-15	-	-	-	-	-	-	-	750	750	750
SAS05-20	-	-	-	-	-	-	-	-	-	-
SAS06	-	-	-	-	-	600	600	1,350	1,350	1,350
SAS07	-	-	-	-	-	600	600	1,350	1,350	1,350
SAS08	-	-	-	-	-	600	1,350	1,350	1,350	1,690
SAS09	-	-	-	-	-	600	1,350	1,350	1,350	1,350
SAS10	-	-	-	-	-	600	1,350	1,350	1,350	1,350
SAS11	-	-	-	-	-	600	600	1,350	1,350	1,350
SAS12	-	-	-	-	-	600	600	600	600	600
SAS13	-	-	-	-	-	600	600	600	600	600
SAS14	-	-	-	-	-	600	600	600	600	600
SAS15	-	-	-	-	-	340	340	1,090	1,090	1,090
SAS16	-	-	-	-	-	940	1,690	2,440	2,440	2,440

Table C.9 – Demand Side Management Additions

(MW Capacity)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAF00	-	-	-	-	-	150	150	150	150	150
CAF01	-	-	-	-	-	151	151	151	151	151
CAF02	-	-	-	-	-	-	-	-	-	-
CAF03	-	-	-	19	101	163	163	163	163	163
CAF04	-	-	-	-	-	78	78	78	78	78
CAF05	-	-	-	-	-	99	99	99	99	99
CAF06	-	-	-	19	34	97	97	169	169	169
CAF07	-	-	-	-	-	58	58	58	58	58
CAF08	-	-	-	-	-	129	129	129	129	129
CAF09	-	-	-	-	-	64	64	64	64	64
CAF10	-	-	-	-	-	68	68	68	68	68
CAF11	-	-	-	-	-	73	211	211	211	211
CAF12	-	-	-	-	-	145	150	150	150	150
CAF13	-	-	-	19	19	26	41	41	41	41
CAF14	-	-	-	-	-	150	150	150	150	150
CAF15	-	-	-	19	19	198	198	198	198	198
SAS01	-	-	-	-	-	161	161	161	161	161
SAS02	-	-	-	-	-	73	140	140	161	161
SAS03	-	-	-	-	-	153	153	153	153	153
SAS04	-	-	-	-	-	153	153	153	153	153
SAS05-10	-	-	-	-	-	150	209	209	209	209
SAS05-15	-	-	-	-	-	-	41	41	41	41
SAS05-20	-	-	-	-	-	154	154	154	154	244
SAS06	-	-	-	-	-	94	150	150	150	150
SAS07	-	-	-	-	-	26	124	124	124	124
SAS08	-	-	-	-	-	198	198	198	198	198
SAS09	-	-	-	-	-	150	150	150	150	150
SAS10	-	-	-	-	-	150	150	150	150	150
SAS11	-	-	-	-	-	26	145	145	145	145
SAS12	-	-	-	-	-	137	137	137	137	137
SAS13	-	-	-	-	-	153	153	153	153	153
SAS14	-	-	-	-	-	153	153	153	153	201
SAS15	-	-	-	-	-	131	211	211	211	211
SAS16	-	-	-	-	-	73	73	73	73	73

ADDITIONAL CEM SENSITIVITY ANALYSIS SCENARIO RESULTS

This section reports the detailed CEM results for an additional set of sensitivity scenarios requested by participants at the August 2006 public input meeting. Specifically, participants requested that sensitivities to scenario variables be tested against different sets of "base" scenario assumptions. All but one of the scenarios in Table 7.1 were intended to examine the CEM's response to varying assumptions around the "medium" (CAF11) case. Participants requested studies that varied the assumptions around the business-as-usual (CAF00), the low cost bookend (CAF14), and the high cost bookend (CAF16) scenarios.

Table C.10 summarizes the additional sensitivity scenarios. Note that sensitivities were only selected if they involve a key scenario variable or planning assumption (such as the planning reserve margin level), or are compatible with respect to how the alternative future scenario was defined. For example, the sensitivities for testing alternative CO_2 adder values are not compatible with the business-as-usual case, since that case assumes no adder to begin with. Regarding the regional transmission project scenario, additional forward price forecasts would be required to support alternative market conditions, which PacifiCorp deemed as too burdensome given the other research priorities. A few other sensitivities were excluded because they are intended to fulfill specific analytical requirements from the Oregon Public Utility Commission, such as SAS15 ("plan to average of super-peak load").

Table C.10 – Additional Sensitivity Scenarios for CEM Optimization

		Alternative Future Scenario Used		
SAS#	**Name**	**Business As Usual (CAF00)**	**Low Cost Bookend (CAF14)**	**High Cost Bookend (CAF15)**
1	Plan to 12% capacity reserve margin	X	X	X
2	Plan to 18% capacity reserve margin	X	X	X
3	CO_2 adder implementation in 2016			
4	Regional transmission project			
5a	CO_2 adder impact on resource selection: $10/ton (1990$)		X	X
5b	CO_2 adder impact on resource selection: $15/ton (1990$)		X	X
5c	CO_2 adder impact on resource selection: $20/ton (1990$)		X	
6	Low wind capital cost	X	X	X
7	High wind capital cost	X	X	X

Tables C.11 through C.15 compare PVRR and resource addition results for each of the additional sensitivity scenarios. The first table reports PVRR. The remaining five tables report nameplate capacity accrued by 2016 for total resources, wind, gas, pulverized coal, and IGCC, respectively.

Table C.11 – Present Value of Revenue Requirements Comparison ($ Billion)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	$19,488	$13,382	$48,825	$24,400
Plan to 18% capacity reserve margin	$19,933	$13,672	$49,936	$24,983
CO_2 adder implementation in 2016	--	--	--	$22,673
Regional transmission project	--	--	--	$24,182
CO_2 adder impact on resource selection: $10/ton (1990$)	--	$19,803	$39,693	$28,551
CO_2 adder impact on resource selection: $15/ton (1990$)	--	$22,303	$44,773	$32,390
CO_2 adder impact on resource selection: $20/ton (1990$)	--	$24,589	$49,234	$36,073
Low wind capital cost	$19,424	$13,523	$47,018	$24,282
High wind capital cost	$19,867	$13,703	$48,123	$24,836

Table C.12 – Total Resources Accrued by 2016 (Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	3,327	1,507	5,338	3,172
Plan to 18% capacity reserve margin	3,831	2,028	6,068	3,918
CO2 adder implementation in 2016	--	--	--	3,584
Regional transmission project	--	--	--	3,543
CO_2 adder impact on resource selection: $10/ton (1990$)	--	1,775	6,010	3,509
CO_2 adder impact on resource selection: $15/ton (1990$)	--	1,735	5,724	3,501
CO_2 adder impact on resource selection: $20/ton (1990$)	--	1,722	5,745	3,488
Low wind capital cost	3,535	1,790	5,708	3,546
High wind capital cost	3,584	1,789	5,687	3,595

Table C.13 – Wind Resources Accrued by 2016 (Nameplate Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	200	400	2,100	600
Plan to 18% capacity reserve margin	1,300	400	2,400	1,500
CO_2 adder implementation in 2016	--	--	--	400
Regional transmission project	--	--	--	900
CO_2 adder impact on resource selection: $10/ton (1990$)	--	400	600	1,200
CO_2 adder impact on resource selection: $15/ton (1990$)	--	400	800	600
CO_2 adder impact on resource selection: $20/ton (1990$)	--	600	2,300	2,800
Low wind capital cost	1,300	500	3,200	2,000
High wind capital cost	200	400	3,100	500

Table C.14 – Gas Resources Accrued by 2016 (Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	25	25	849	125
Plan to 18% capacity reserve margin	125	548	1,631	734
CO_2 adder implementation in 2016	--	--	--	125
Regional transmission project	--	--	--	125
CO_2 adder impact on resource selection: $10/ton (1990$)	--	302	1,361	1,029
CO_2adder impact on resource selection: $15/ton (1990$)	--	125	1,336	1,236
CO_2adder impact on resource selection: $20/ton (1990$)	--	125	1,211	1,361
Low wind capital cost	50	75	1,029	402
High wind capital cost	602	75	849	684

Table C.15 – Pulverized Coal Resources Accrued by 2016 (Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	1,690	--	2,440	1,350
Plan to 18% capacity reserve margin	1,690	--	2,440	1,690
CO_2 adder implementation in 2016	--	--	--	1,690
Regional transmission project	--	--	--	1,690
CO_2 adder impact on resource selection: $10/ton (1990$)	--	--	2,440	1,090
CO_2 adder impact on resource selection: $15/ton (1990$)	--	--	2,440	750
CO_2 adder impact on resource selection: $20/ton (1990$)	--	--	2,440	--
Low wind capital cost	1,690	750	2,440	1,350
High wind capital cost	1,690	750	2,440	1,350

Table C.16 – IGCC Resources Accrued by 2016 (Megawatts)

Name	Alternative Future Scenario Used			
	Business As Usual (CAF00)	Low Cost Bookend (CAF14)	High Cost Bookend (CAF15)	Medium Load Growth (CAF11)
Plan to 12% capacity reserve margin	200	--	500	200
Plan to 18% capacity reserve margin	200	--	500	--
CO_2 adder implementation in 2016	--	--	--	200
Regional transmission project	--	--	--	--
CO_2 adder impact on resource selection: $10/ton (1990$)	--	--	1,494	--
CO_2 adder impact on resource selection: $15/ton (1990$)	--	--	997	--
CO_2 adder impact on resource selection: $20/ton (1990$)	--	--	500	--
Low wind capital cost	200	--	500	--
High wind capital cost	--	--	500	--

For the detailed CEM results tables, fossil fuel resource additions are reported as nameplate megawatts accrued as of the year listed. Wind resources are reported as the estimated megawatt peak capacity contribution accrued as of the year listed. The annual figures are not additive. Contract quantities were also grossed up by the planning reserve margin to reflect the assumption that contract purchases are firm.

Table C.17 – CEM Results: Aggregate Resource Additions

		Resource Additions (MW)										
Scenario	**PVRR** (millions)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**PVRR** (Million$/ 2016 MW)
BAU/ 12% PRM	$ 19,488	45	486	449	978	1,263	2,431	2,880	2,972	3,046	3,327	5.9
BAU/ 18% PRM	$ 19,933	271	1,002	975	1,496	1,789	2,881	3,185	3,456	3,543	3,831	5.2
BAU/Low Wind Cap Cost	$ 19,424	236	749	715	1,237	1,528	2,693	3,174	3,443	3,243	3,535	5.5
BAU/High Wind Cap Cost	$ 19,867	45	748	722	1,236	1,523	2,683	2,855	3,231	3,302	3,584	5.5
Low Cost Bookend/ 12% PRM	$ 13,382	68	142	68	296	416	1,413	1,404	1,489	1,406	1,507	8.9
Low Cost Bookend/ 18% PRM	$ 13,672	106	681	475	831	943	1,950	1,938	2,025	1,927	2,028	6.7
Low Cost Bookend/ $10 CO_2	$ 19,803	68	424	211	576	688	1,680	1,672	1,759	1,674	1,775	11.2
Low Cost Bookend/ $15 CO_2	$ 22,303	85	423	209	575	673	1,653	1,641	1,724	1,640	1,735	12.9
Low Cost Bookend/ $20 CO_2	$ 24,589	98	422	209	572	659	1,652	1,638	1,722	1,638	1,722	14.3
Low Cost Bookend/ Low Wind Cap Cost	$ 13,523	122	420	207	572	691	1,670	1,662	1,722	1,634	1,790	7.6
Low Cost Bookend/ High Wind Cap Cost	$ 13,703	45	425	209	575	694	1,669	1,660	1,711	1,632	1,789	7.7
High Cost Bookend/ 12% PRM	$ 48,825	-	839	1,008	1,724	2,233	3,528	3,911	4,399	4,738	5,338	9.1
High Cost Bookend/ 18% PRM	$ 49,936	82	1,404	1,565	2,308	2,837	4,158	4,506	5,283	5,521	6,068	8.2
High Cost Bookend/ $10 CO_2	$ 39,693	82	1,109	1,268	2,001	2,511	3,828	4,237	4,907	5,137	6,010	6.6
High Cost Bookend/ $15 CO_2	$ 44,773	72	1,108	1,267	1,999	2,510	3,808	4,204	4,653	5,143	5,724	7.8
High Cost Bookend/ $20 CO_2	$ 49,234	82	1,109	1,268	2,001	2,511	3,838	4,259	4,917	5,172	5,745	8.6

		Resource Additions (MW)										
Scenario	PVRR (millions)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	PVRR (Million$/ 2016 MW)
Low Cost Bookend/ Low Wind Cap Cost	$ 47,018	368	1,130	1,298	2,031	2,528	3,863	4,211	4,661	5,152	5,708	8.2
Low Cost Bookend/ High Wind Cap Cost	$ 48,123	226	1,106	1,270	1,995	2,511	3,778	4,158	4,645	5,090	5,687	8.5

Note: Business as Usual (BAU)

Table C.18 – CEM Results: Wind Resource Additions

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	200	200	200	200	200	200	200	200	200	200
BAU/ 18% PRM	1,200	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
BAU/ Low Wind Cap Cost	1,100	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
BAU/ High Wind Cap Cost	200	200	200	200	200	200	200	200	200	200
Low Cost Bookend/ 12% PRM	300	300	300	300	300	300	300	400	400	400
Low Cost Bookend/ 18% PRM	400	400	400	400	400	400	400	400	400	400
Low Cost Bookend/ $10 CO_2$	300	300	300	300	300	300	400	400	400	400
Low Cost Bookend/ $15 CO_2$	400	400	400	400	400	400	400	400	400	400
Low Cost Bookend/ $20 CO_2$	500	500	500	500	500	500	500	600	600	600
Low Cost Bookend/ Low Wind Cap Cost	500	500	500	500	500	500	500	500	500	500
Low Cost Bookend/ High Wind Cap Cost	200	200	300	300	300	300	300	400	400	400
High Cost Bookend/ 12% PRM	-	200	300	300	300	600	600	600	1,400	2,100
High Cost Bookend/ 18% PRM	300	300	300	300	300	400	400	400	600	2,400
High Cost Bookend/ $10 CO_2$	300	300	300	300	300	400	400	400	600	600
High Cost Bookend/ $15 CO_2$	300	300	300	300	300	400	400	400	600	800
High Cost Bookend/ $20 CO_2$	300	300	300	300	300	400	400	400	800	2,300
Low Cost Bookend/ Low Wind Cap Cost	2,200	2,800	2,800	2,800	2,800	2,800	2,800	3,100	3,100	3,200
Low Cost Bookend/ High Wind Cap Cost	1,000	1,000	1,000	1,000	1,000	2,000	2,100	3,000	3,100	3,100

Table C.19 – CEM Results: Front Office Transactions

Figures shown are megawatts acquired in each year, Contract quantities were grossed up by the planning reserve margin to reflect the assumption that contract purchases are firm.
Annual figures are not additive.

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/12% PRM	-	440	404	933	1,218	1,380	1,079	1,171	1,244	1,326
BAU/18% PRM	-	719	692	1,213	1,505	1,380	934	1,205	1,291	1,380
BAU/ Low Wind Cap Cost	-	499	465	987	1,278	1,380	1,111	1,380	1,180	1,272
BAU/ High Wind Cap Cost	-	703	676	1,190	1,478	1,096	1,267	894	965	1,247
Low Cost Bookend/ 12% PRM	-	74	-	228	347	1,337	1,328	1,377	1,294	1,370
Low Cost Bookend/ 18% PRM	-	575	369	726	837	1,296	1,285	1,372	1,273	1,374
Low Cost Bookend/ \$10 CO_2	-	355	143	507	620	1,310	1,274	1,362	1,277	1,378
Low Cost Bookend/ \$15 CO_2	-	338	124	490	588	1,373	1,360	1,369	1,285	1,380
Low Cost Bookend/ \$20 CO_2	-	324	112	474	561	1,380	1,366	1,380	1,296	1,380
Low Cost Bookend/ Low Wind Cap Cost	-	298	85	450	569	1,378	1,370	1,380	1,291	698
Low Cost Bookend/ High Wind Cap Cost	-	380	127	492	612	1,362	1,352	1,380	1,302	708
High Cost Bookend/ 12% PRM	-	791	914	1,631	1,728	1,380	1,013	1,002	1,244	995
High Cost Bookend/ 18% PRM	-	1,303	1,136	1,879	2,294	1,363	210	488	690	971
High Cost Bookend/ \$10 CO_2	-	1,027	1,160	1,874	2,083	1,380	1,038	459	674	553
High Cost Bookend/ \$15 CO_2	-	1,036	1,195	1,908	2,111	1,377	1,022	972	697	749
High Cost Bookend/ \$20 CO_2	-	1,027	1,160	1,874	2,083	1,380	1,051	459	649	987
Low Cost Bookend/ Low Wind Cap Cost	-	679	846	1,561	1,153	1,370	968	856	597	1,107
Low Cost Bookend/ High Wind Cap Cost	-	880	1,019	1,725	2,175	1,380	1,009	914	1,342	1,189

Table C.20 – CEM Results: Gas Additions, Including Combined Heat and Power

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	-	-	-	-	-	25	25	25	25	25
BAU/ 18% PRM	-	-	-	-	-	125	125	125	125	125
BAU/ Low Wind Cap Cost	-	-	-	-	-	50	50	50	50	50
BAU/ High Wind Cap Cost	-	-	-	-	-	602	602	602	602	602
Low Cost Bookend/ 12% PRM	-	-	-	-	-	-	-	-	-	25
Low Cost Bookend/ 18% PRM	-	-	-	-	-	548	548	548	548	548
Low Cost Bookend/ \$10 CO_2	-	-	-	-	-	302	302	302	302	302
Low Cost Bookend/ \$15 CO_2	-	-	-	-	-	50	50	125	125	125
Low Cost Bookend/ \$20 CO_2	-	-	-	-	-	75	75	125	125	125
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	25	25	75	75	75
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	75	75	75	75	75
High Cost Book-end/ 12% PRM	-	-	25	25	417	849	849	849	849	849
High Cost Book-end/ 18% PRM	-	-	327	327	327	1,631	1,631	1,631	1,631	1,631
High Cost Book-end/ \$10 CO_2	-	-	25	25	327	1,361	1,361	1,361	1,361	1,361
High Cost Book-end/ \$15 CO_2	-	-	-	-	302	1,336	1,336	1,336	1,336	1,336
High Cost Book-end/ \$20 CO_2	-	-	25	25	327	1,211	1,211	1,211	1,211	1,211
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	904	1,004	1,004	1,004	1,004	1,029
Low Cost Bookend/ High Wind Cap Cost	-	-	25	25	25	849	849	849	849	849

Table C.21 – CEM Results: IGCC Additions

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	-	-	-	-	-	-	-	-	-	200
BAU/ 18% PRM	-	-	-	-	-	-	-	-	-	200
BAU/Low Wind Cap Cost	-	-	-	-	-	-	-	-	-	200
BAU/High Wind Cap Cost	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ 12% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ 18% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$10 CO_2	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$15 CO_2	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$20 CO_2	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	-	-	-	-	-
High Cost Book-end/ 12% PRM	-	-	-	-	-	-	-	500	500	500
High Cost Book-end/ 18% PRM	-	-	-	-	-	-	-	500	500	500
High Cost Book-end/ \$10 CO_2	-	-	-	-	-	-	-	500	500	1,494
High Cost Book-end/ \$15 CO_2	-	-	-	-	-	-	-	500	500	997
High Cost Book-end/ \$20 CO_2	-	-	-	-	-	-	-	500	500	500
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	-	-	500	500	500
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	-	-	500	500	500

Table C.22 – CEM Results: Pulverized Coal Additions

(Nameplate MW)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	-	-	-	-	-	940	1,690	1,690	1,690	1,690
BAU/ 18% PRM	-	-	-	-	-	940	1,690	1,690	1,690	1,690
BAU/ Low Wind Cap Cost	-	-	-	-	-	940	1,690	1,690	1,690	1,690
BAU/ High Wind Cap Cost	-	-	-	-	-	940	940	1,690	1,690	1,690
Low Cost Bookend/ 12% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ 18% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$10 CO2	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$15 CO_2	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$20 CO_2	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	-	-	-	-	750
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	-	-	-	-	750
High Cost Book-end/ 12% PRM	-	-	-	-	-	940	1,690	1,690	1,690	2,440
High Cost Book-end/ 18% PRM	-	-	-	-	-	940	2,440	2,440	2,440	2,440
High Cost Book-end/ \$10 CO_2	-	-	-	-	-	940	1,690	2,440	2,440	2,440
High Cost Book-end/ \$15 CO_2	-	-	-	-	-	940	1,690	1,690	2,440	2,440
High Cost Book-end/ \$20 CO_2	-	-	-	-	-	940	1,690	2,440	2,440	2,440
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	940	1,690	1,690	2,440	2,440
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	940	1,690	1,690	1,690	2,440

Table C.23 – CEM Results: Demand-side Management Additions

(MW Capacity)

Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
BAU/ 12% PRM	-	-	-	-	-	41	41	41	41	41
BAU/ 18% PRM	-	-	-	-	-	153	153	153	153	153
BAU/ Low Wind Cap Cost	-	-	-	-	-	73	73	73	73	73
BAU/ High Wind Cap Cost	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ 12% PRM	-	-	-	-	-	7	7	7	7	7
Low Cost Bookend/ 18% PRM	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$10 CO_2	-	-	-	-	-	-	-	-	-	-
Low Cost Bookend/ \$15 CO_2	-	-	-	-	-	145	145	145	145	145
Low Cost Bookend/ \$20 CO_2	-	-	-	-	-	99	99	99	99	99
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	-	-	145	145	145	145	145
Low Cost Bookend/ High Wind Cap Cost	-	-	-	-	-	150	150	150	150	150
High Cost Bookend/ 12% PRM	-	-	-	-	19	198	198	198	198	198
High Cost Bookend/ 18% PRM	-	19	19	19	133	140	140	140	140	140
High Cost Bookend/ \$10 CO_2	-	-	-	19	19	46	46	46	46	46
High Cost Bookend/ \$15 CO_2	-	-	-	19	24	46	46	46	46	46
High Cost Bookend/ \$20 CO_2	-	-	-	19	19	198	198	198	198	198
Low Cost Bookend/ Low Wind Cap Cost	-	-	-	19	19	97	97	97	97	97
Low Cost Bookend/ High Wind Cap Cost	-	-	-	19	85	195	195	195	195	195

APPENDIX D – SUPPLEMENTARY PORTFOLIO INFORMATION

This appendix reports additional information for the risk analysis portfolios discussed in Chapter 7. This information consists of carbon dioxide emissions quantity and cost data, as well as a component cost breakdown of the stochastic mean Present Value of Revenue Requirements (PVRR) reported for the risk analysis portfolios.

CARBON DIOXIDE EMISSIONS

Table D.1 shows cumulative CO_2 emissions for 2007 through 2026 attributable to retail sales only, allocated to each state.

Table D.2 reports unit emission costs (cents/MWh) by new fossil fuel resource for the risk analysis portfolios considered as finalists for preferred portfolio selection (Group 2 portfolios). The results are reported for 2016 based on the $8/ton CO_2 adder case.

Table D.1 – CO_2 Emissions Attributable to Retail Sales by State

Group 1 Portfolios

ID	CO_2 Emissions attributable to Retail Sales, 2007-2026 (1000 Tons)						
	System Total	California	Oregon	Washington	Utah	Idaho	Wyoming
RA1	1,120,694	17,481	262,468	85,363	500,054	65,432	189,897
RA2	1,111,948	17,342	260,377	84,678	496,227	64,910	188,413
RA3	1,115,336	17,388	261,003	84,889	498,000	65,073	188,984
RA4	1,121,824	17,494	262,636	85,420	500,715	65,475	190,084
RA5	1,115,003	17,388	261,047	84,899	497,671	65,077	188,920
RA6	1,104,309	17,228	258,687	84,122	492,675	64,484	187,112
RA7	1,089,439	16,997	255,229	82,988	486,009	63,619	184,596
RA8	1,128,175	17,594	264,156	85,917	503,490	65,854	191,163
RA9	1,123,075	17,517	263,001	85,538	501,159	65,564	190,296
RA10	1,119,534	17,462	262,184	85,270	499,558	65,360	189,699
RA11	1,109,867	17,308	259,850	84,508	495,373	64,779	188,049
RA12	1,110,384	17,320	260,043	84,566	495,486	64,824	188,146

Group 2 Portfolios

ID	CO_2 Emissions attributable to Retail Sales, 2007-2026 (1000 Tons)						
	$8 Adder	California	Oregon	Washington	Utah	Idaho	Wyoming
RA13	1,127,571	17,586	264,045	85,886	503,165	65,828	191,061
RA14	1,064,710	16,624	249,713	81,179	474,567	62,234	180,393
RA15	1,068,540	16,683	250,584	81,465	476,315	62,453	181,041
RA16	1,057,885	16,517	248,100	80,652	471,557	61,832	179,227
RA17	1,075,848	16,796	252,296	82,027	479,570	62,881	182,278

Table D.2 – Unit Emission Costs for Group 2 Risk Analysis Portfolio Resources, 2016

Portfolio, Location, and Fossil Fuel Resources	Generation (GWh)	SO_2 Cost	NO_X Cost	Hg Cost	CO_2 Cost
		Cents/MWh			
Portfolio RA13					
East					
Utah supercritical pulverized coal	1,642	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	4,011	16.1	39.1	5.9	898.8
Utah supercritical pulverized coal 2 (added in 2017)	-				
Wyoming supercritical pulverized coal 2 (added in 2018)	-				
Combined Heat and Power	140	0.1	13.2	1.4	286.4
West					
Combined Heat and Power	395	0.1	13.1	1.4	287.0
Portfolio RA14					
East					
Utah supercritical pulverized coal	1,584	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	3,864	16.1	39.1	5.9	898.8
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,283	0.1	4.8	2.0	411.5
Combined Cycle Combustion Turbine, G Class, 1x1 w/ duct firing	1,571	0.1	4.8	2.0	405.7
Combined Heat and Power	143	0.1	13.2	1.4	286.4
West					
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,086	0.1	4.8	2.0	416.6
Combined Heat and Power	402	0.1	13.1	1.4	287.0
Portfolio RA15					
East					
Utah supercritical pulverized coal	1,607	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	3,926	16.1	39.1	5.9	898.8
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,382	0.1	4.8	2.0	411.5
Combined Heat & Power	142	0.1	13.2	1.4	286.4
West					
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	1,956	0.1	4.8	2.0	416.6
Combined Heat and Power	392	0.1	13.1	1.4	287.0
Portfolio RA16					
East					
Utah supercritical pulverized coal	1,544	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	3,821	16.1	39.1	5.9	898.8
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,320	0.1	4.8	2.0	411.5
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,320	0.1	4.8	2.0	411.5
Combined Heat and Power	143	0.1	13.2	1.4	286.4
West					
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	2,058	0.1	4.8	2.0	416.6
Combined Heat and Power	401	0.1	13.1	1.4	287.0
Portfolio RA17					
East					
Utah supercritical pulverized coal	1,651	15.8	38.1	5.8	880.5
Wyoming supercritical pulverized coal	4,044	16.1	39.1	5.9	898.8
Combined Heat & Power	141	0.1	13.2	1.4	286.4
West					
Combined Cycle Combustion Turbine, F Class, 2x1 w/ duct firing	1,836	0.1	4.8	2.0	416.6
Combined Heat and Power	382	0.1	13.1	1.4	287.0

Figures D.1 and D.2 show the CO_2 intensity (as measured by CO_2 tons produced per megawatt-hours generated) for the Group 2 portfolios in the \$8/ton and \$61/ton CO_2 adder cases from 2007 through 2016.

Figure D.1 – Annual CO_2 Intensity, 2007-2016 (\$8 CO_2 Adder Case)
(From generation plus amount assigned to net wholesale market purchases)

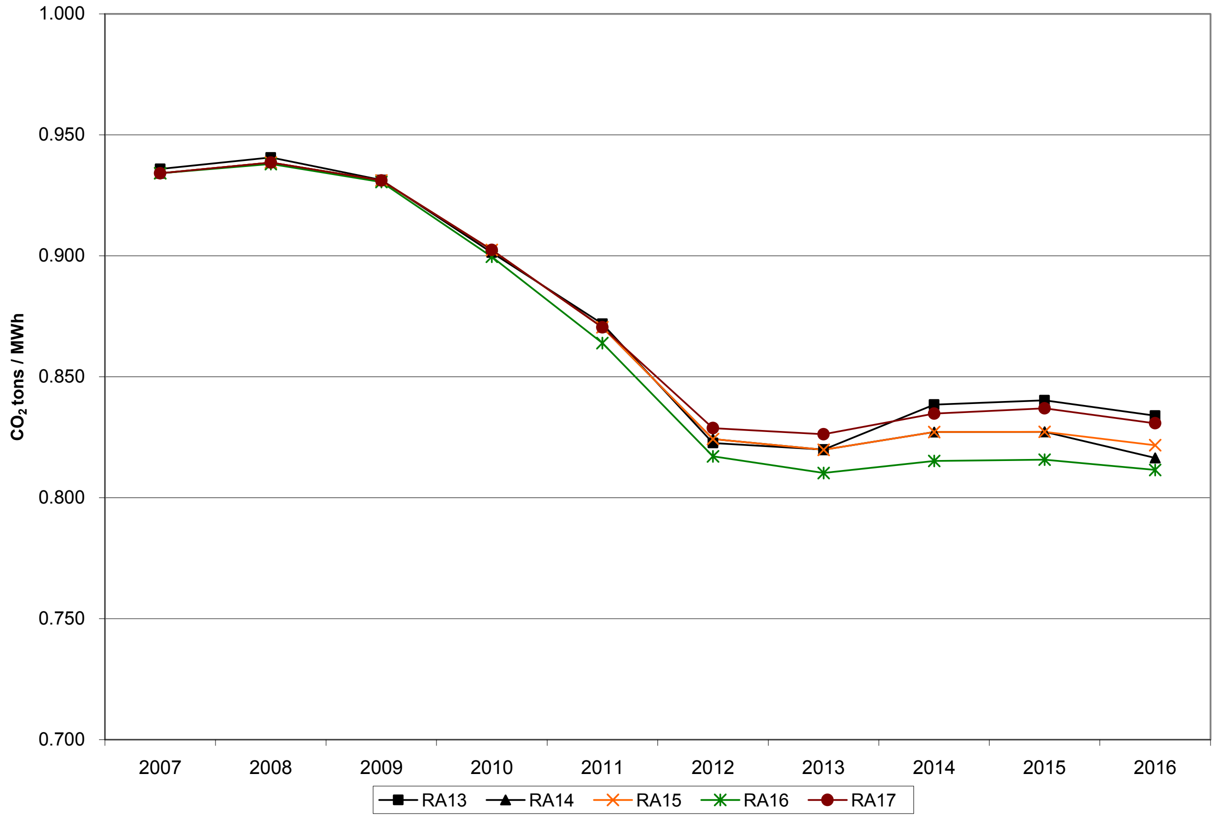


Figure D.2 – Annual CO_2 Intensity, 2007-2016 ($61 CO_2 Adder Case)
(From generation plus amount assigned to net wholesale market purchases)

PORTFOLIO PVRR COST COMPONENT COMPARISON

Tables D.3 through D.5 shows the breakdown of each portfolio's stochastic mean PVRR by variable and fixed cost components. These costs reflect the $8/ton CO_2 cost adder scenario. Table D.3 reports Group 1 risk analysis portfolios assuming a cap-and-trade compliance strategy as described in the Environmental Externality Cost section of Chapter 6. Tables D.4 and D.5 report the cost component breakdown for Group 2 risk analysis portfolios for both the CO_2 cap-and-trade and tax compliance strategies.

Table D.3 – Group 1: Portfolio PVRR Cost Components (Cap-and-Trade Strategy)

Cost Component ($000)	RA1	RA2	RA3	RA4	RA5	RA6
Variable Cost						
Total Fuel Cost	10,965,989	11,219,657	10,747,203	11,071,618	10,863,819	11,466,519
Variable O&M Cost	1,666,016	1,688,456	1,653,825	1,685,170	1,664,323	1,609,748
Total Emission Cost	(491,456)	(524,670)	(583,581)	(494,617)	(541,909)	(633,384)
Long Term Contracts and Front Office Transactions	4,063,902	2,989,769	3,993,441	2,784,539	2,990,020	3,942,403
Spot Market Balancing						
Sales	(7,171,405)	(6,701,180)	(7,028,212)	(6,484,120)	(6,654,682)	(6,790,395)
Purchases	4,097,605	4,256,922	4,156,083	4,506,043	4,064,023	4,526,764
Energy Not Served	629,175	506,358	578,218	599,325	407,713	649,402
Total Variable Net Power Costs	**13,759,825**	**13,435,313**	**13,516,978**	**13,667,958**	**12,793,306**	**14,771,056**
Real Levelized Fixed Costs	**7,585,994**	**8,078,725**	**7,998,119**	**7,821,194**	**9,444,528**	**7,541,457**
Total PVRR	**21,345,820**	**21,514,038**	**21,515,097**	**21,489,152**	**22,237,834**	**22,312,513**

Cost Component ($000)	RA7	RA8	RA9	RA10	RA11	RA12
Variable Cost						
Total Fuel Cost	11,011,967	10,861,455	10,650,718	10,807,128	10,476,806	10,584,210
Variable O&M Cost	1,662,836	1,661,127	1,600,405	1,621,957	1,626,325	1,625,553
Total Emission Cost	(615,865)	(493,480)	(528,346)	(517,475)	(576,401)	(583,010)
Long Term Contracts and Front Office Transactions	2,986,551	3,765,884	3,855,182	4,014,157	3,914,856	3,572,191
Spot Market Balancing						
Sales	(6,755,434)	(6,813,214)	(6,840,773)	(7,064,978)	(7,013,125)	(6,751,045)
Purchases	4,138,731	4,552,750	4,467,441	4,140,306	4,167,820	4,456,951
Energy Not Served	496,355	738,005	823,267	698,510	583,165	695,599
Total Variable Net Power Costs	**12,925,142**	**14,272,526**	**14,027,895**	**13,699,605**	**13,179,447**	**13,600,449**
Real Levelized Fixed Costs	**8,717,103**	**7,199,096**	**7,935,847**	**8,182,478**	**8,589,968**	**8,153,395**
Total PVRR	**21,642,245**	**21,471,622**	**21,963,742**	**21,882,083**	**21,769,415**	**21,753,844**

Table D.4 – Group 2: Portfolio PVRR Cost Components (CO_2 Cap-and-Trade Compliance Strategy)

Cost Component ($000)	RA13	RA14	RA15	RA16	RA17
Variable Cost					
Total Fuel Cost	11,879,724	12,740,475	12,687,088	12,893,187	12,496,322
Variable O&M Cost	1,677,644	1,688,639	1,686,253	1,695,132	1,675,585
Total Emission Cost	(500,740)	(686,096)	(675,164)	(707,522)	(660,752)
Long Term Contracts and Front Office Transactions	4,463,924	3,381,073	3,498,015	3,400,556	3,959,801
Spot Market Balancing					
Sales	(7,970,503)	(8,139,526)	(8,129,546)	(8,311,108)	(8,156,926)
Purchases	5,011,221	4,781,176	4,805,009	4,626,554	4,858,925
Energy Not Served	942,290	546,119	614,736	504,489	670,814
Total Variable Net Power Costs	**15,503,559**	**14,311,859**	**14,486,390**	**14,101,289**	**14,843,769**
Real Levelized Fixed Costs	**6,506,394**	**7,247,005**	**7,145,760**	**7,523,537**	**6,906,261**
Total PVRR	**22,009,953**	**21,558,864**	**21,632,150**	**21,624,826**	**21,750,030**

Table D.5 – Group 2: Portfolio PVRR Cost Components (CO_2 Tax Compliance Strategy)

Cost Component ($000)	RA13	RA14	RA15	RA16	RA17
Variable Cost					
Total Fuel Cost	11,879,724	12,740,475	12,687,088	12,893,187	12,496,322
Variable O&M Cost	1,677,644	1,688,639	1,686,253	1,695,132	1,675,585
Total Emission Cost	4,419,596	4,232,883	4,243,852	4,211,342	4,258,307
Long Term Contracts and Front Office Transactions	4,463,924	3,381,073	3,498,015	3,400,556	3,959,801
Spot Market Balancing					
Sales	(7,970,503)	(8,139,526)	(8,129,546)	(8,311,108)	(8,156,926)
Purchases	5,011,221	4,781,176	4,805,009	4,626,554	4,858,925
Energy Not Served	942,290	546,119	614,736	504,489	670,814
Total Variable Net Power Costs	**20,423,895**	**19,230,838**	**19,405,407**	**19,020,153**	**19,762,827**
Real Levelized Fixed Costs	**6,506,394**	**7,247,005**	**7,145,760**	**7,523,537**	**6,906,261**
Total PVRR	**26,930,289**	**26,477,843**	**26,551,166**	**26,543,691**	**26,669,089**

APPENDIX E – STOCHASTIC RISK ANALYSIS METHODOLOGY

OVERVIEW

PacifiCorp analyzes potential portfolios over possible future conditions to assess the performance of each portfolio under uncertainty. Global Energy's Planning and Risk (PaR) model is used to perform a stochastic assessment of portfolios in which system loads, hydroelectric energy availability, thermal unit outages, and wholesale electric and gas prices are varied to reflect uncertainty. Stochastic representations of these variables include specific volatility and correlations parameters. In the case of four of the five uncertainties described previously (PaR treats thermal outages separately), there are potentially short-term and long-term stochastic parameters (volatilities and correlations). The following is a discussion of the stochastic model specification, the short-term and long-term parameters and results of the stochastic simulation studies.

STOCHASTIC VARIABLES

PacifiCorp's analysis is performed for the following stochastic variables:

- Fuel prices (natural gas prices for the company's western and eastern control areas),
- Electricity market prices for Mid-Columbia (Mid C), California – Oregon Border (COB), Four Corners, and Palo Verde (PV),
- Electric transmission area loads (California, Idaho, Oregon, Utah, Washington and Wyoming regions) and
- Hydroelectric generation

The PaR's stochastic tool determines a set of stochastic model parameters based on data entered by the user. During model execution, PaR makes time path dependent Monte Carlo draws for each stochastic variable based on the input parameters. The Monte Carlo draws are of percentage deviations from the expected forward value of the variables. In the case of natural gas prices, electricity prices and regional loads, PaR applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

<u>The PaR Stochastic Model</u>

PaR's stochastic model is a two factor (a short-run and a long-run factor) short-run mean reverting model. Variable processes assume normality or log-normality as appropriate. Separate volatility and correlation parameters are used for modeling the short-run and long-run factors. The short-run process defines seasonal effects on forward variables, while the long-run factor defines random structural effects on electricity and natural gas markets and retail load regions. The short-run process is designed to capture the seasonal patterns inherent in electricity and natural gas markets and seasonal pressures on electricity demand. Mean reversion represents the speed at which a disturbed variable will return to its seasonal expectation. With respect to market prices, the long-run factor should be understood as an expected equilibrium, with the Monte Carlo draws defining a possible forward equilibrium state. In the case of regional electricity loads, the Monte Carlo draws define possible forward paths for electricity demand.

The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance.

The long-run parameters are derived from a random-walk with drift regression. The standard error of the random-walk regression defines the long-run volatility for the regional electricity load variables. In the case of the natural gas and electricity market prices, the standard error of the random walk regression is interpolated with the volatilities from the company's Official Forward Price curve for March 31, 2006 over the twenty year study period. The long-run regression errors are correlated to capture inter-variable effects from changes to expected market equilibrium for natural gas and electricity markets as well as the impacts from changes in expected regional electricity loads.

For a detailed specification of the PaR stochastic model, please refer to the 2004 IRP Appendix G.

STOCHASTIC OUTPUT

Presented below are graphical stylized outputs from the 100 stochastic iterations made by the Planning and Risk model. Eastern and western natural gas and electricity market prices (Figures E.1 through E.8) are presented showing the frequency of prices for 2007 and 2016. In the case of stochastic regional electricity loads (Figures E.9 through E.13), the 90th, 75th, 25th and 10th percentiles as well as the mean are presented. For hydroelectric generation (Figures E.14 and E.15), the 75th, 50th, 25th percentiles are presented.

Figure E.1 – 2007 Frequency of Eastern (Palo Verde) Electricity Market Prices – 100 Iterations

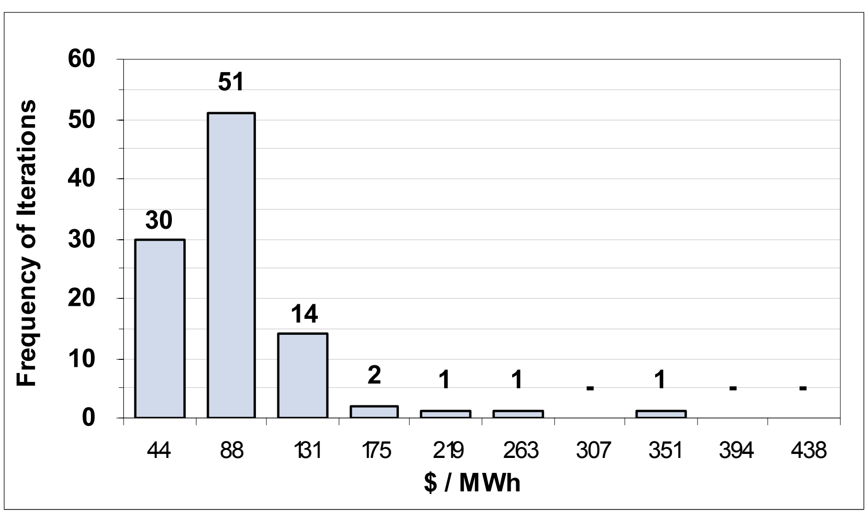


Figure E.2 – 2016 Frequency of Eastern (Palo Verde) Electricity Market Prices – 100 Iterations

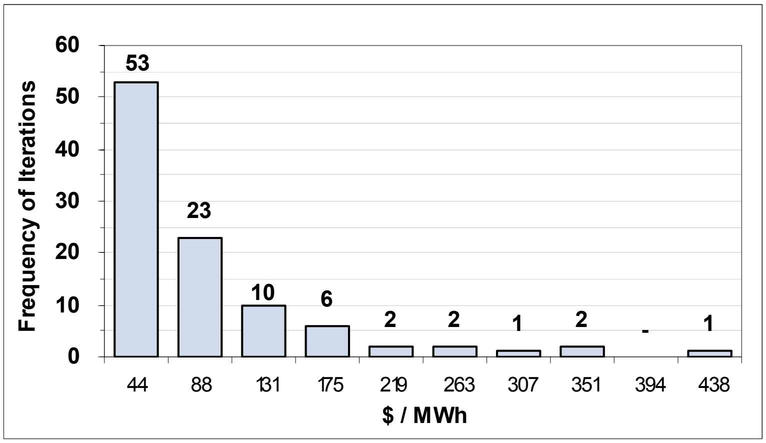


Figure E.3 – 2007 Frequency of Western (Mid C) Electricity Market Prices – 100 Iterations

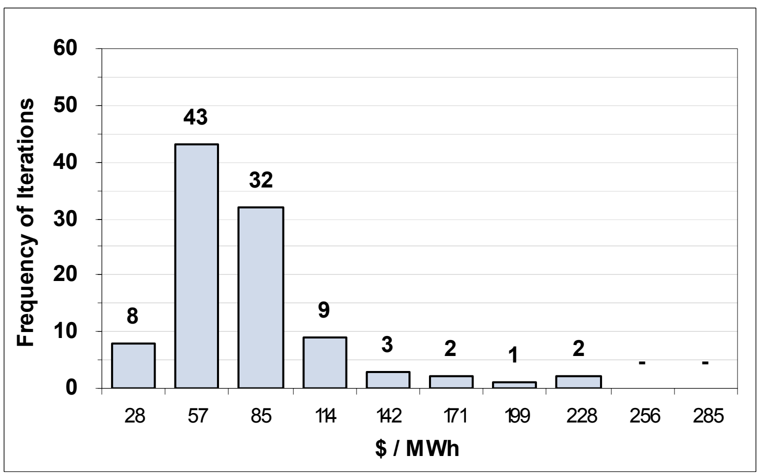


Figure E.4 – 2016 Frequency of Western (Mid C) Electricity Market Prices – 100 Iterations

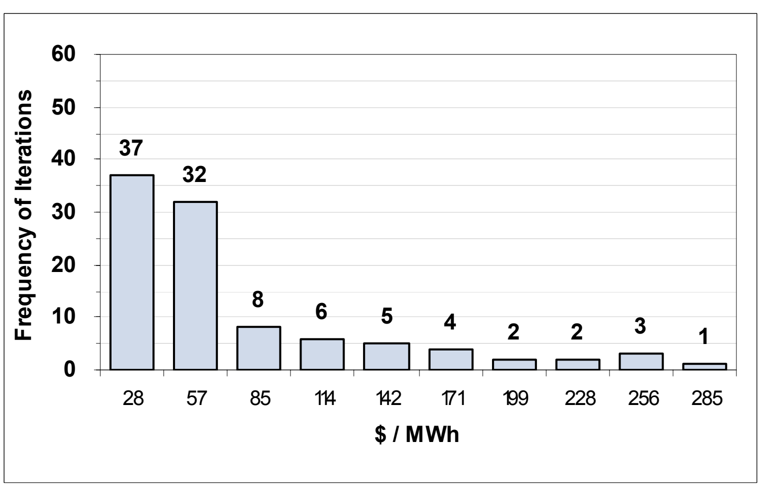


Figure E.5 – 2007 Frequency of Eastern Natural Gas Market Prices – 100 Iterations

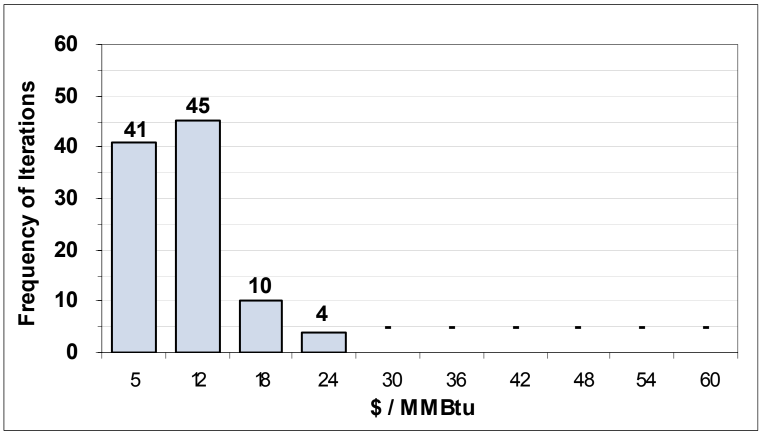


Figure E.6 – 2016 Frequency of Eastern Natural Gas Market Prices – 100 Iterations

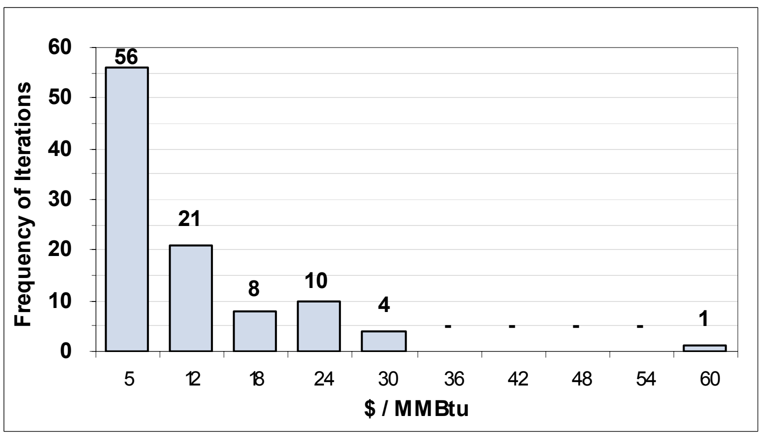


Figure E.7 – 2007 Frequency of Western Natural Gas Market Prices – 100 Iterations

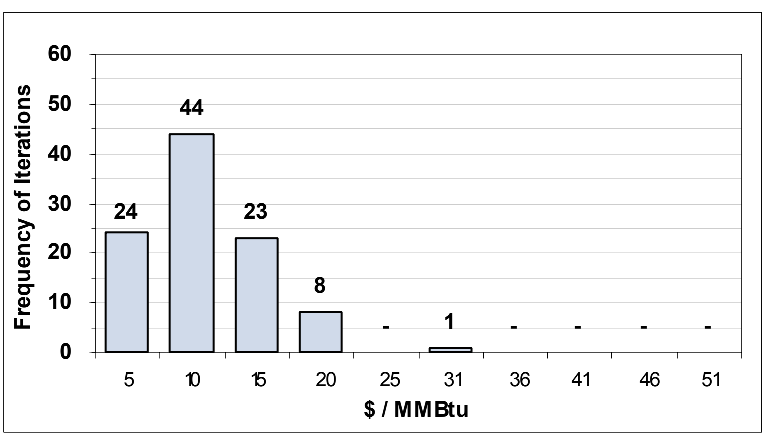


Figure E.8 – 2016 Frequency of Western Natural Gas Market Prices – 100 Iterations

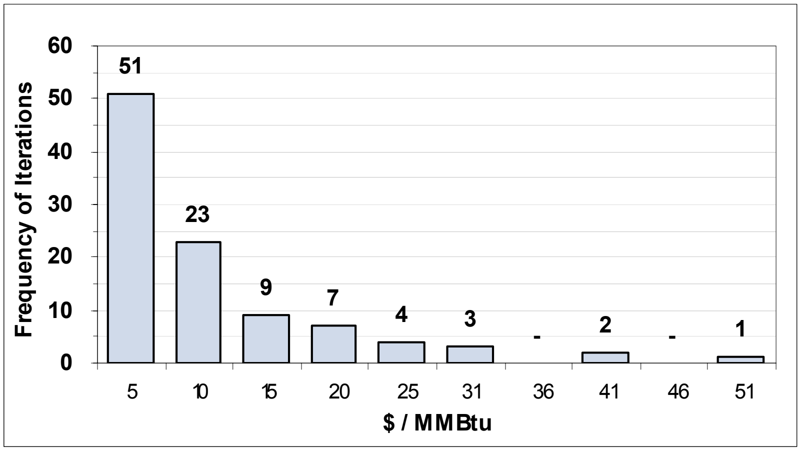


Figure E.9 – Goshen Loads

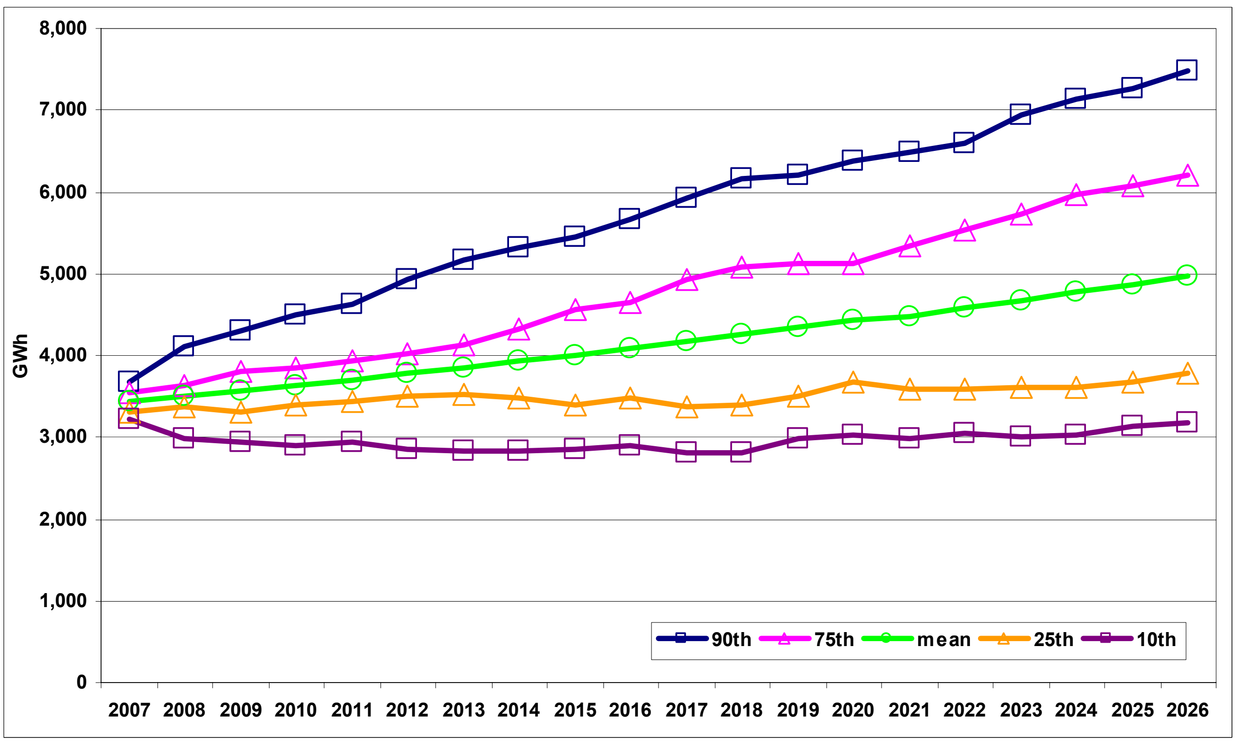


Figure E.10 – Utah Loads

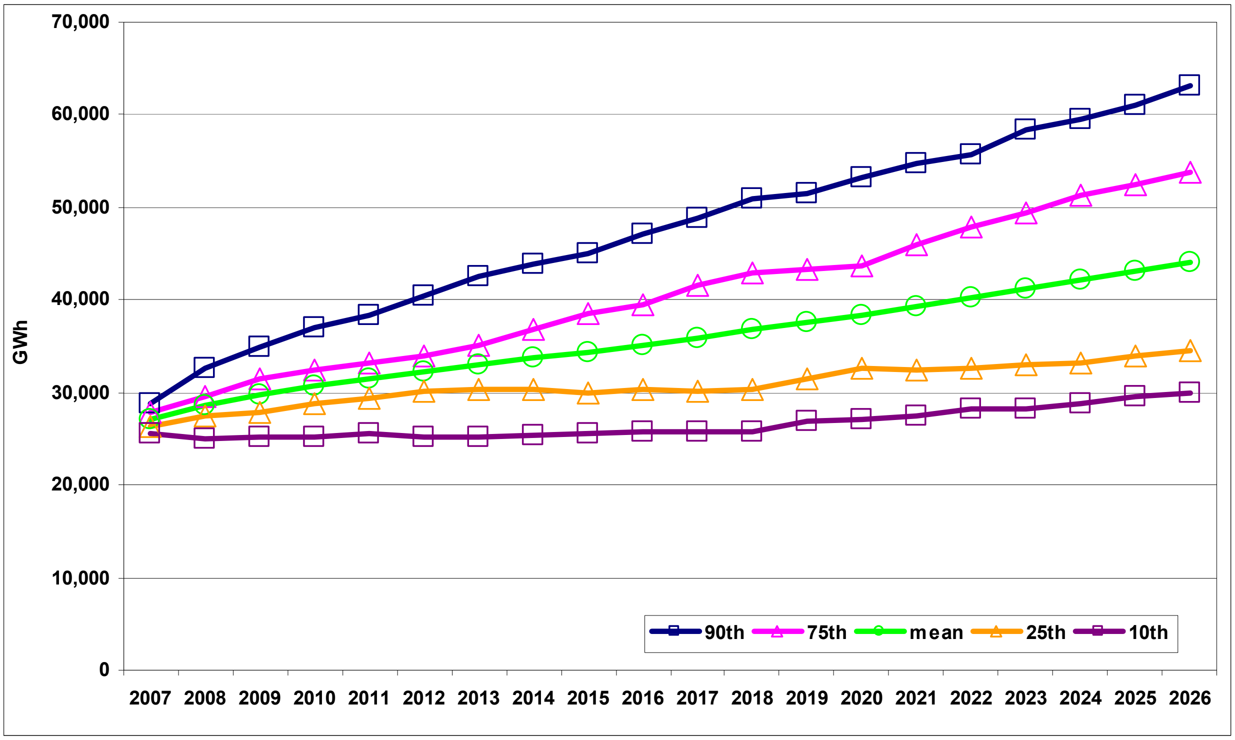


Figure E.11 – Washington Loads

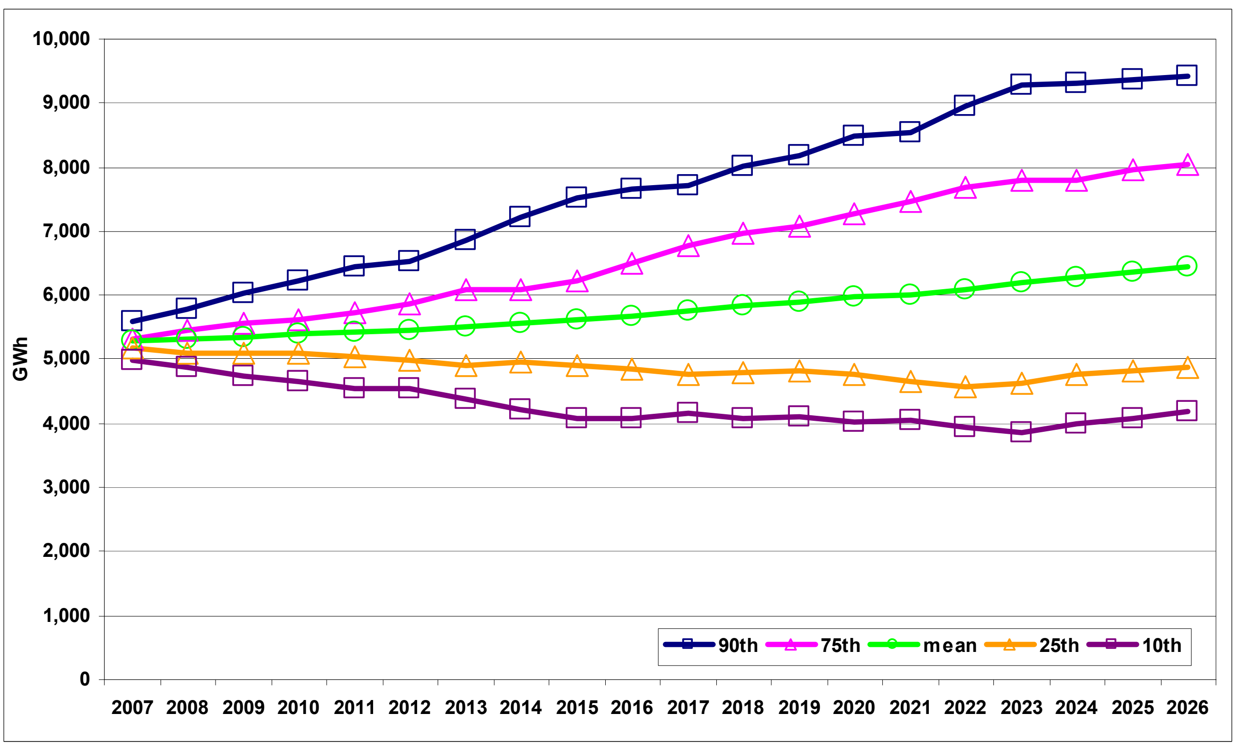


Figure E.12 – West Main (California and Oregon) Loads

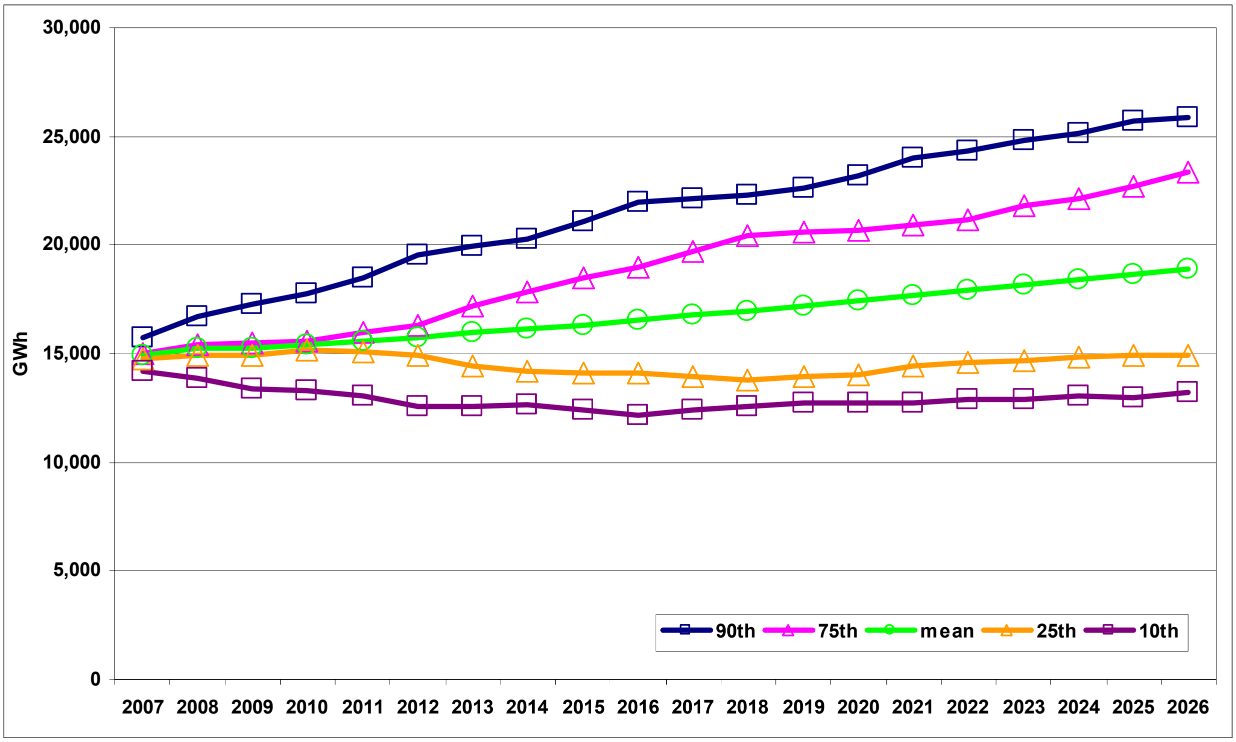


Figure E.13 – Wyoming Loads

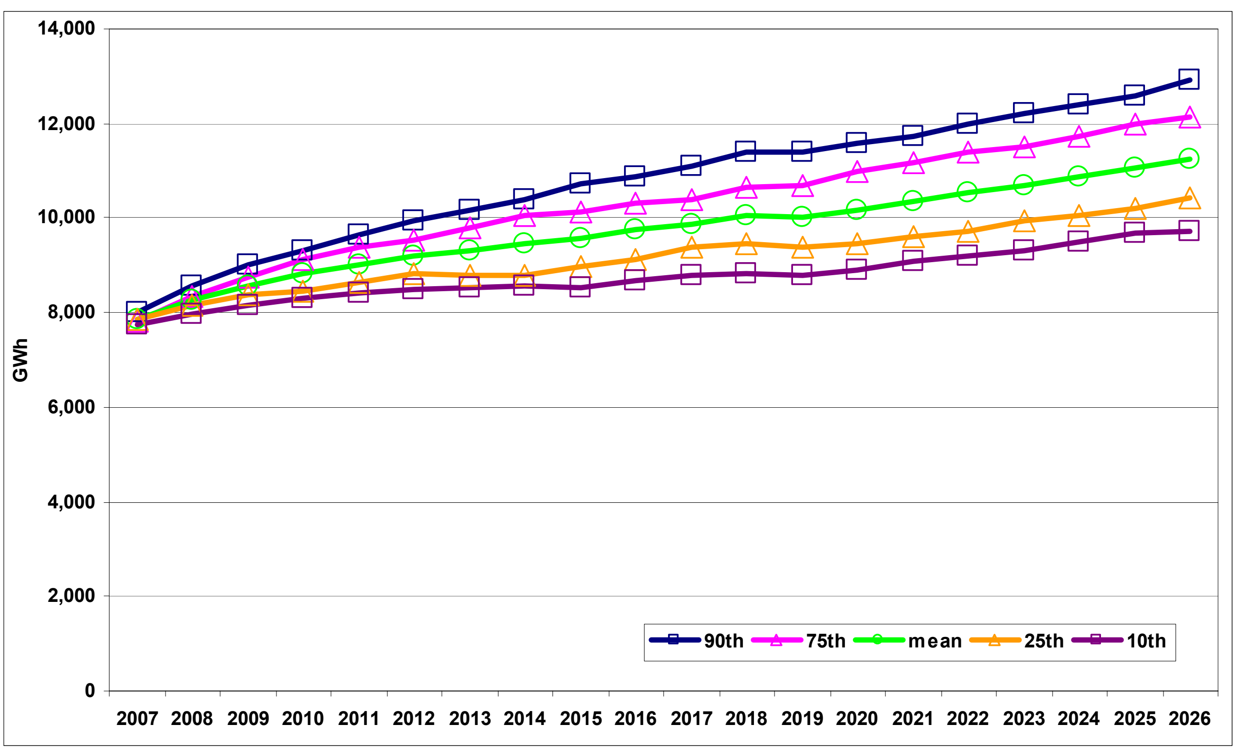


Figure E.14 – 2007 Hydroelectric Generation Percentile

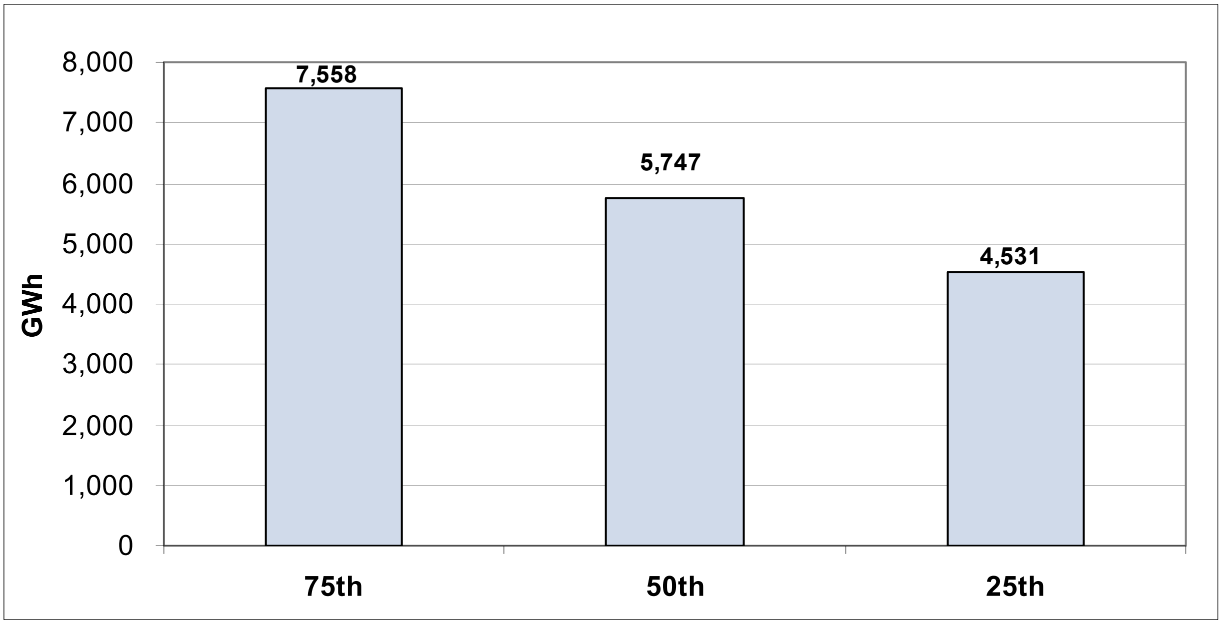
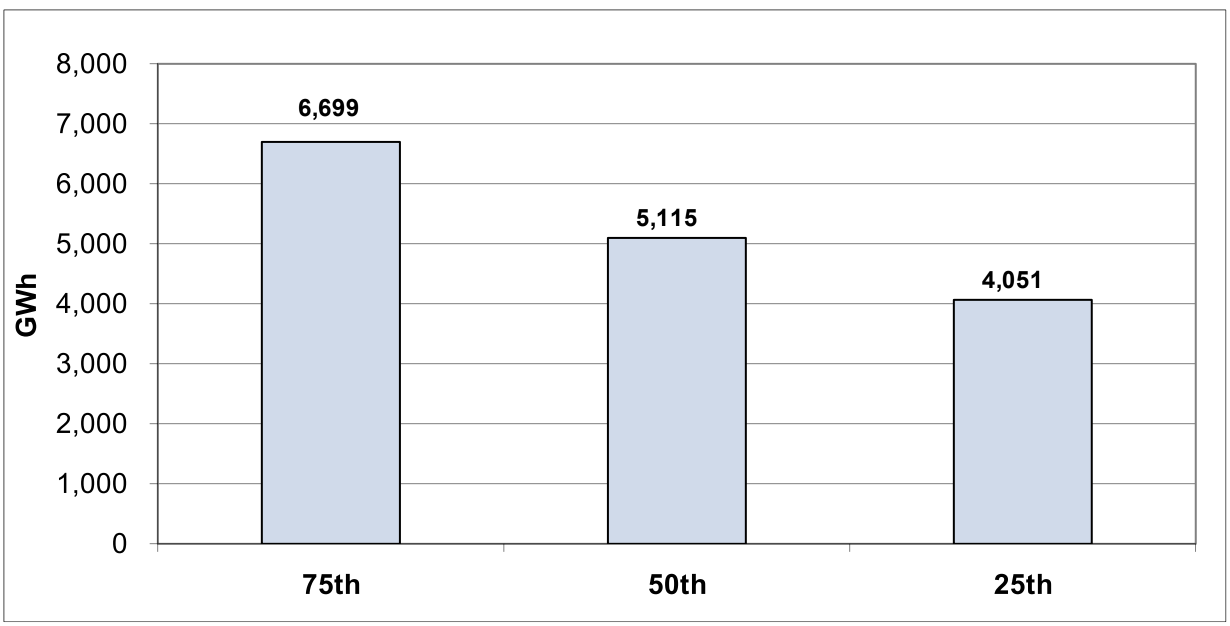


Figure E.15 – 2016 Hydroelectric Generation Percentile



APPENDIX F – PUBLIC INPUT PROCESS

A critical element of this resource plan is the public input process. PacifiCorp has pursued an open and collaborative approach involving the Commissions, customers and other stakeholders in PacifiCorp's planning process 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 Commissions and other interested and affected 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 received information. As reflected in the report, many of the comments provided by the participants have been adopted by PacifiCorp and have contributed 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 three locations, Salt Lake City, Portland and Cheyenne (Starting from the April 20, 2006), using telephone and video conferencing technology, to encourage wide participation while minimizing travel burdens and respecting everyone's busy schedules.

The 2007 public input meetings were augmented by a series of focused technical workshops to provide an opportunity to discuss complex topics for a multi-state utility in more detail.

PARTICIPANT LIST

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

Intervenors

- Citizen's Utility Board of Oregon
- Committee for Consumer Services State of Utah
- Energy Trust of Oregon
- Energy Strategies, LLC
- Industrial Customers of Northwest Utilities
- Mountain West Consulting, LLC

- Northwest Energy Efficiency Alliance
- Northwest Power and Conservation Council
- NW Energy Coalition
- Oregon Department of Energy
- Renewables Northwest Project
- 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 Air Quality
- Utah Division of Public Utilities
- Utah Energy Office
- Utah Geological Survey
- Utah Governor Office
- Utah Legislative Watch
- Wasatch Clean Air Coalition
- Western Resource Advocates
- West Wind Wires
- Wyoming Industrial Energy Consumers
- Wyoming Office Of Consumer Advocacy

Others

- Portland General Electric (PGE)
- Puget Sound Energy (PSE)
- Avista Utilities
- Quantec LLC
- John Klingele
- Global Energy Decisions, LLC

PacifiCorp extends its gratitude for the time and energy these participants have given to the resource 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, three technical workshops and three general meetings between the 2004 and 2007 IRP process which discussed various issues including inputs and assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public input meetings and the technical workshops.

<u>2005 Public Process</u>

May 18, 2005 – General Meeting

- Results of IRP Stakeholder Satisfaction Survey
- Overview of PacifiCorp Transmission
- Procurement Update
  - Implementation of Supply Side Actions in 2004 IRP Action Plan
  - Renewables RFP
  - RFP 2009
  - Front Office Transactions
- DSM Update
  - DSM in the 2004 IRP
  - Class 1 and Class 2 Update
  - DSM Procurement
- Update on Inputs and Assumptions
- Update on Models
  - PaR Conversion
  - Capacity Expansion Module

August 3, 2005 – General Meeting

- Load Forecasting Annual Review
  - National Economic Outlook
  - Regional Economic Review
  - Tools and Inputs of the Residential Forecast
  - Preliminary Residential Sales Forecast
- IRP Benchmarking Study
  - Scope and Overview
  - Findings
- IRP Action Plan Update
  - RFP 2003 B Renewable
  - RFP 2009
  - RFP 2011
  - Transmission (Regional Initiatives)
  - DSM Update
  - CEM Model Update
- 2004 IRP Update Plan
  - Outline
  - Schedule

October 5, 2005 – General Meeting

- Update on IRP Acknowledgement
- Load and Resource Balance Update
- New Portfolio Development / Overview of Analysis
- Status of Update Filing
- Progress on IRP Action Plan
  - RFP 2003 B Renewable, RFP 2009

  - DSM Update
- Load Forecasting Technical Workshop - Annual Review
  - Comparisons of State Economic Forecasts
  - Commercial Electric Model Design and Inputs
  - Preliminary Commercial Economic and Sales Forecast

2006 Public Process

December 7, 2005 – General Meeting
- Overview of 2006 IRP Public Process
  - IRP Team Update
  - 2006 IRP Work Plan
  - PIM Participant Working Group (“WG”) Approach
  - Public Process Expectations
- 2006 IRP Studies
- 2004 IRP Update Summary and Revised Action Plan

January 13, 2006 – Renewables Workshop
- Review and discuss Wind Resource Analysis Plan
- Discuss Capacity Expansion Module (CEM) renewable supply curve modeling approach
- Summary
- Comments, Questions, and Suggestions
- Z-Statistic Method for Estimating Resource Peak Load Carrying Capability

January 24, 2006 – Load Forecasting Workshop
- Preliminary Industrial Energy Sales Forecast
  - State by State
    - Mix and Growth by Sector – 2007 and 2017
    - Sector by Sector Model Review
- Hourly Load Forecast
  - General Model Specification by Jurisdiction
  - Forecast Process
  - Improvements in the Process
  - System Coincident Peak Demand & Jurisdiction Contribution Results
  - State Peak Demands
  - Next Steps
- Price Elasticity
  - Price Elasticity in Current Models
  - Econometric Elasticity Calculations
  - Price Reaction of Customers Who Called About the Rate Change
  - Elasticity Among Customer Sub-Groups
  - Potential Further Research

February 10, 2006 – Demand-Side Management Workshop

- 2004 IRP DSM modeling Review
- Modeling Plan for 2006 IRP
  - Planning Drivers and Objectives
  - Modeling Approach Overview
  - Program Assumptions for 2006 IRP
- 2005 DSM RFP Summary and Challenges
- Summation and Next Steps

April 20, 2006 – General Meeting

Update on IRP Inputs, Assumptions, and Studies

- Climate Change Policy Developments
- CO2 Analysis in the 2006 IRP
- Integrated Gasification Combined Cycle (IGCC) Analysis Update
- Treatment of IGCC in the 2006 IRP
- Long-Term Load Forecast
- Preliminary Load & Resource Balance

May 10, 2006 – General Meeting

- Natural Gas and Electricity Forecasts
- Renewables Studies
- Procurement Update

June 7, 2006 – General Meeting

- Demand-Side Management: Class I & III Resource Assessment Update
- Procurement Update: Demand-Side Management
- Procurement Update: Supply-Side Resources
- IRP Resource Alternatives
- IRP Transmission Analysis Approach
- Portfolio Analysis Scenarios and Risk Analysis
- Resource Adequacy/Capacity Planning Margin

August 23, 2006 – General Meeting

- Introduction: Capacity Expansion Module (CEM) Analysis
- Scenario Review
- General Observations
  - Total Portfolio Costs
  - Generation, Demand-Side Management (DSM), and Market Purchases
  - Transmission
  - Sensitivity Studies
- CO2 Adder Impacts
- Summary Results
- Modeling Conclusions and Candidate Portfolio Development Process

Appendix:

- Modeling Results - Annual Resource Additions by Scenario

October 31, 2006 – General Meeting
- Candidate Portfolio Development
- Detailed Simulation Results and Conclusions
  - Stochastic Cost/Risk Trade-off Analysis Results
  - Reliability Analysis Results
  - CO_2 emissions for \$8/ton CO_2 adder case
- Quantec DSM Proxy Supply Curve Study
- Feedback on Capacity Expansion Module Results
- IRP Document Overview

2007 Public Process

February 1, 2007 – General Meeting
- Status of the Integrated Resource Plan
- Status of the 2012 Request for Proposal
- Conclusions resulting from stakeholder feedback
- Proposed path forward
- Impact on the current Integrated Resource Plan
- Discussion and Comments

April 18, 2007 – General Meeting
- Load Forecast Update
  - Summary of Changes to Forecast
  - Changes in Economic Conditions
  - Major Sales Changes by Jurisdiction
- Load and Resource Balance Update
- Preferred Portfolio
- Action Plan
- Portfolio Modeling Update
  - Risk Analysis Portfolio Development
  - Cost and Risk Performance Results
  - Customer Rate Impacts
  - Carbon Dioxide Emissions Footprint
  - Supply Reliability Measures
- Class 2 DSM Decrement Analysis

PARKING LOT ISSUES

During the course of the public input meetings, certain concerns or questions needed additional explanation from PacifiCorp. These questions or issues 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 different complex questions that covered all aspects of the IRP.

Additionally, for the 2007 planning cycle, PacifiCorp provided meeting summaries for each of the public meetings reflecting a synopsis of what was discussed during the meeting. These summaries can be found on the internet website (http://www.pacificorp.com/Article/Article23848.html) and provide additional details on a particular IRP public meeting.

PUBLIC REVIEW OF IRP DRAFT DOCUMENT

This section summarizes the substantive comments on the draft IRP document submitted by IRP public participants and provides PacifiCorp's responses. The comments and responses are grouped by topic.

At the public meeting held on October 31, 2006, the company requested that parties focus on compliance with state IRP standards and guidelines when submitting comments on the draft IRP. PacifiCorp distributed the IRP draft document for public comment on April 20, 2007, with a comment due date of May 11, 2007. The company received comments from seven parties in time to be considered for the final IRP report:

- Utah Public Service Commission Staff (UPSC)
- The Utah Committee of Consumer Services (UCCS)
- The Utah Division of Public Utilities (UDPU)
- Utah Association of Energy Users (UAE)
- Western Resource Advocates (WRA)
- The NW Energy Coalition (NWEC)
- Renewable Northwest Project (RNP)

To characterize the comments at a high level, parties sought justification for, or cited perceived deficiencies in, (1) the scope of resources evaluated and their characterization (DSM, renewables, and IGCC in particular), (2) the treatment and interpretation of modeled risk factors and reliability, and (3) the decision criteria used to select preferred portfolio resources. A number of parties also submitted detailed questions and requests for supporting data.

To address the written comments, PacifiCorp modified the final IRP report to include more justification of its analytical conclusions and resource decisions, and answered specific technical questions to the extent possible given the IRP filing schedule. PacifiCorp also supplemented the "IRP Regulatory Compliance" appendix with two tables that outline how the company interpreted and complied with each of the IRP standards for Oregon and Utah (Tables I.3 and I.4 in Appendix I). The company considered the written comments when completing these tables. Responses to questions and data requests that could not be included in the final IRP report or addressed in this section will be handled as separate follow-up responses.

Portfolio Optimality

A number of parties disagree with, or at least question, whether the preferred portfolio development process meets Utah IRP standards and Guidelines with respect to "selection of the optimal set of resources given the expected combination of costs, risk and uncertainty." For example, the UPSC asked for clarification on how the company's statement in Chapter 2 —"The emphasis of the IRP is to determine the most robust resource plan under a reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future"—is consistent with this guideline. The UCCS states that they are not convinced of the optimality of the preferred portfolio. The UPSC and UAE believe that fixing resources for the CEM results in suboptimal resource selection. For example, the UAE states that the Group 2 portfolios appear to be suboptimal because the CEM was used to determine the build pattern of gas plants and front office transactions, while coal and wind resources were set. WRA, on the other hand, states that model results should not be used as an alternative to informed judgment and critical thinking.

Response: PacifiCorp agrees with WRA that modeling results should not be used as the sole basis for determining an optimal portfolio given the multi-objective and subjective nature of the resource planning exercise. PacifiCorp's model solutions are dependent on model structure and the underlying assumptions. Thus, model results need to be interpreted in the light of real-world considerations. One of these considerations, cited in Chapter 7, are resource decision constraints resulting from new and expected state resource policies.

In the context of capacity expansion modeling with the CEM, any one model solution is only optimal for the single set of assumptions used for the associated model run and should not be considered optimal in any broader sense due to the deterministic nature of the model and the single set of input assumptions. In contrast, the role of the Planning and Risk model has been to determine the stochastic cost and risk impacts of alternative resource strategies, not to determine an optimal portfolio from a stochastic simulation standpoint. These two models together, with their different perspectives on the resource planning problem, and across a variety of input assumptions, have thus helped to support the overall resource decision.

In regard to the impact of fixing resources on model solution optimality, PacifiCorp points out that the main purpose of the CEM is to limit the set of potential resources to a manageable size for more detailed stochastic production cost analysis and to analyze alternative futures. The CEM was successfully used for this purpose. As discussed in Chapter 7, development of the Group 2 portfolios was informed by both Group 1 risk analysis results and resource policy considerations. CEM optimization was only used as a portfolio refinement tool; specifically, to evaluate the timing of the CCCT resources and select an optimized quantity of front office transactions resources to meet PacifiCorp's annual load obligation and planning reserve.

Finally, PacifiCorp augmented its discussion on preferred portfolio selection in Chapter 7 by laying out the strategic justification for the portfolio. In essence, the company believes that its preferred portfolio represents a good balance of resource types with complementary strengths *that together* help to minimize resource risk. The idea of "robustness" under a reasonably wide range of potential futures reflects a decision goal to account for the possibility of various high-cost outcomes for customers and to avoid resource decisions that, in aggregate, lead to such an outcome being realized. The best way to accomplish this is through resource diversification, which the preferred portfolio proxy resources are intended to provide. Consequently, PacifiCorp's definition of the optimal resource set is one that offers the best compromise of cost and risk when considering alternative futures and multiple stakeholder priorities. PacifiCorp notes that none of the state IRP standards provide definitive criteria for judging how a resource plan for a multi-state utility has achieved optimality under risk and uncertainty, and given diverse resource preferences and policies among its state jurisdictions.

Planning Reserve Margin Selection and Resource Needs Assessment

A number of the parties disagreed with PacifiCorp's use of a 12 percent planning reserve margin for its preferred portfolio, citing analysis results from the 2007 IRP that seem to support a higher margin. Others requested more justification for the selection decision. One party, UAE, endorsed the 12 percent planning reserve margin, stating that it has been adequately supported by PacifiCorp's cost-risk tradeoff analysis. UAE also recommended further planning margin analysis including incorporating an assessment of market response to "high carbon risk, price caps, or other externalities." The UPSC and UCCS requested an explanation of changes in certain capacity balance components relative to the components reported in the 2004 IRP, as well as cited inter-jurisdictional cost allocation issues associated with potential Energy Not Served.

Response: PacifiCorp expanded its discussion on the choice of a planning reserve margin in Chapter 7 ("Planning Reserve Margin Selection"). PacifiCorp's position is that the planning reserve margin should not be considered an immutable constraint on the company's resource decisions given a time of rapid public policy evolution and wide uncertainty over the resulting downstream cost impacts. Therefore, PacifiCorp now advocates a planning reserve *range* of 12 to 15 percent, and initially targets 12 percent for its preferred portfolio to develop some added planning flexibility as public policy continues to evolve and regional resource adequacy standards are addressed.

UPSC requested an explanation for the increase in wholesale sales reported in the 2007 IRP capacity balance relative to that reported in the 2004 and 2004 IRP Update balances. This change is due to a reporting change for the delivery portion of exchange contracts. Exchange contract deliveries are no longer reported in the Purchase and Renewable components as was done for the 2004 IRP and 2004 IRP Update. These delivery amounts now appear in the Sales component.

Inter-jurisdictional cost allocation issues are outside of the purview of the IRP process. This information will be provided as a separate response.

Relationship of PacifiCorp's IRP with its Business Plan

A number of the Utah parties expressed concern about how PacifiCorp's IRP is related to its Business Plan, and that PacifiCorp might not be meeting its IRP obligation under the Utah Standards and Guidelines to ensure that its business plan is "directly related to its Integrated Resource Plan." (Procedural Issue no. 9) The UDPU also pointed out a lack of sufficient information that shows that the two plans are consistent, and suggests that PacifiCorp does not comply with the Standards and Guidelines on this basis.

Response: PacifiCorp's Business Plan is directly related to the IRP; the business planning process is informed by the IRP resource analysis, the action plan, and subsequent procurement activities. Because the latest Business Plan was undergoing development during the latter half of the 2007 IRP cycle, it made sense to coordinate on certain resource assumptions. These assumptions are fully described in Chapter 7. Going forward, the 2007 IRP will be used to inform the next version of the Business Plan.

The 2007 IRP Action Plan

The UDPU believes that the draft IRP does not provide "detailed focus" on actions over the next two years as stated in Utah IRP standard 4(e). Areas that need more coverage include renewable portfolio standards, Klamath River hydroelectric relicensing, renewable resources, local renewable projects (MEHC commitment U33), and sulfur hexafluoride emissions control (MEHC commitment 42a).

Response: PacifiCorp believes that the level of detail on specific actions is comparable to what was provided in previous IRP action plans. This level of detail garnered no criticism from the UDPU in the past, and the company believes the level of detail is sufficient. Actions for acquiring up to 1,400 megawatts of cost-effective renewables are presented in the Renewables Action Plan, filed concurrently with this IRP in accordance with MEHC commitments.

Demand-Side Management

Comments centered on the lack of modeling of Class 2 (energy efficiency) programs, and the expectation that the forthcoming DSM potentials study will address parties' concerns regarding benefit capture and market potential. The UDPU identified several issues: (1) a lack of data on Class 2 DSM, (2) concern that the IRP models "do not accurately reflect the costs and benefits associated with DSM resources", citing the results of the CEM low and high DSM potential scenario results, (3) variable amounts of DSM and CHP resources were not subjected to risk analysis using the PaR model. The UDPU also requested that the company explain how the DSM potentials study results will be incorporated in the next IRP. The UCCS requested more explanation of the DSM resources included in the initial load and resource balance. The WRA expressed concern that an insufficient amount of DSM has been included in the IRP.

Response: PacifiCorp noted in the IRP report that Class 2 DSM could not be modeled in the CEM due to the lack of supply curve data for PacifiCorp's service territory; rather, Class 2 DSM was treated as a decrement to the load forecast as in prior IRPs, while DSM decrement values determined using stochastic production cost modeling. A discussion of the handling of Class 2 DSM is provided in Chapter 6 ("Public Utility Commission Guidelines for Conservation Program Analysis in the IRP").

For the DSM potentials study, the company will receive cost-supply curves for Class 1, Class 2, and Class 3 DSM programs, which will be input into the IRP models once they have been verified and approved for use. The company will also receive a set of CHP and customer-owned standby generator resource characterizations that will be included in the models as well.

Responding to the UDPU comment on performing manual DSM/CHP optimization using the stochastic PaR model, PacifiCorp notes that using the PaR in this manner is not practical given the long model run-times, which reach 16 to 18 hours. This limitation has been communicated to Utah parties during previous IRP cycles, and was one of the reasons why PacifiCorp acquired the CEM (to have an automated resource selection capability).

Regarding the UCCS request for more explanation on the DSM included in the load and resource balance, Table 4.10 in Chapter 4 summarizes existing DSM program contributions to the balance. Tables A.8 and A.15 in Appendix A outline the amounts and timing of Class 2 DSM load reductions. Expected Class 1 program contributions are described in Table A.13.

Market Reliance, Availability, and Price Risk

Several parties were concerned with the level of market purchases included in the preferred portfolio, and requested verification of market availability to support these amounts and other data and analysis. The UPSC requested that PacifiCorp provide supporting analysis of cost-risk trade-offs of market reliance versus building resources. The RNP and NWEC stated their concern that PacifiCorp overestimates the wholesale value of coal and other base load plants (and undervalues short-lead-time resources such as SCCTs and DSM) given the impact of emission performance standards and renewable portfolio standards.

Response: PacifiCorp added a new section in Chapter 7 that provides more information on the company's market purchase strategy and expected market availability.

Regarding analysis of cost-risk tradeoff analysis of market reliance versus building, PacifiCorp refers parties to a number of risk analysis portfolios and a sensitivity study designed to directly address the cost-risk tradeoffs of assets and market reliance. These results are documented in Chapter 7. For example, the section titled "Resource Strategy Risk Reduction" describes the comparison of portfolios with and without front office transactions after 2011. The chapter also describes a stochastic simulation study in which PacifiCorp replaced a 2012 base load resource with front office transactions.

PacifiCorp acknowledges and shares parties' concerns over the potential market impacts of new resource constraints imposed by renewable generation requirements and CO_2 emission performance standards. Action plan item no. 17 (Chapter 8, Table 8.2) addresses modeling enhancements to assist in the analysis of such issues. The company notes that such analysis capability is not present in existing market models that are designed to simulate integrated system operation. PacifiCorp has been exploring CEM customization possibilities with the model vendor, Global Energy Decisions.

Scope of Resource Analysis

Most of the parties identified resources that PacifiCorp did not model but thought it should have, or else requested an explanation for why they were not modeled. Examples include solar, geothermal, and storage technologies. The UCCS requested that PacifiCorp investigate an approach that enables comparable treatment of all technologies throughout the modeling process even if they have been excluded for modeling purposes on the basis of screening criteria. The UPSC questioned why the company is not addressing retrofits, retirements, and distributed technologies as resource options. The UDPU inquired as to PacifiCorp plans to build a landfill gas power plant in the near future. The UPSC and UCCS questioned why geothermal was not modeled given that it has the lowest reported total resource cost in Tables 5.3 and 5.4 (The UPSC also questioned the difference in geothermal capital costs between the value reported in the IRP and the Blundell economic study.) The WRA stated that technology risk should not be used as a screen to eliminate resources from further consideration, and also called for more robust analysis of CHP potential. The UAE recommended that the planning horizon be extended to facilitate analysis of nuclear and other long-lead-time resources. Both the NWEC and WRA stated that the

CO_2 risk analysis was flawed by not including IGCC with carbon capture and sequestration as an appropriately modeled resource (i.e., allowing the CEM to select carbon capture and sequestration for an IGCC plant once it becomes economic to do so).

Response: A summary of the process for selecting resources to include in the IRP models is provided in Tables I.3 and I.4 in Appendix I (See the response to Oregon Guideline 1.a.1 in Table I.3, and the response to Utah Standard 4.b.ii in Table I.4). As noted, PacifiCorp intends to investigate a CEM modeling process that accommodates a broader range of technologies within the limitations of the company's IRP models. PacifiCorp will consider retirements and retrofits as resource options in future IRPs. Consideration of these resource options and others will be made in the context of an overall review of resource potentials, data availability, technical feasibility, and modeling constraints.

Concerning the observation on the low reported geothermal total resource cost, PacifiCorp expanded its discussion on the geothermal project cost characterization and treatment of the renewable production tax credit for geothermal projects (Chapter 5, 'Other Renewable Resources"). On the differences between reported geothermal capital costs in the IRP and Blundell economic study, PacifiCorp notes that the UCCS submitted a formal data request on May 16, 2007 on this issue, to which the company will respond separately from this IRP report.

Regarding the consideration of technology risk as a factor in resource screening, PacifiCorp points out this is just one factor that was used to develop the modeled resource list. PacifiCorp agrees that technology risk should not be used as a screen to exclude resources from further consideration. Other factors considered by the company included the outlook for commercial maturity during the 10-year investment horizon that was the focus of this IRP, and most importantly, practical modeling considerations of the CEM. PacifiCorp quickly approached the resource limit recommended by the model vendor and began to scale back resources and define generic proxy resources for front office transaction and renewables. The associated learning experience will be useful as the company addresses the anticipated expansion of resource options for the next IRP.

Regarding landfill gas plants, PacifiCorp has reviewed potential sites for such projects in the Rocky Mountain Power and Pacific Power service territories, and selected two sites in Oregon for which feasibility studies have been conducted. The initial findings and recommendation are undergoing review. The company is also looking at five other landfill sites (one in Washington and four in Utah) for possible feasibility analysis.

As to the UAE's recommendation to extend the planning horizon to facilitate analysis of nuclear and other long-lead-time resources, the company will consider this change as it formulates its next IRP modeling plan.

Concerning the modeling of IGCC with carbon capture and sequestration, PacifiCorp notes that the current version of the CEM does not allow the modeling of plant retrofits such as carbon capture and sequestration. However, the company is acquiring a CEM model upgrade that includes this modeling capability, and expects to implement this functionality in time for the next IRP. Nevertheless, PacifiCorp disagrees with the WRA's contention that the CO_2 risk analysis is inherently flawed to the extent that it "should be completely reworked before any conclusions must be drawn" because of the way IGCC-based carbon capture and sequestration was addressed in the IRP models. PacifiCorp's modeling of IGCC for this IRP first looked at the ability of carbon-capture-ready IGCC to stand on its own merits, and then performed various sensitivity analyses to investigate the potential cost impacts of adding carbon capture and sequestration. PacifiCorp believes that the uncertainties associated with carbon capture and sequestration are too great to consider it as an investment that customers and investors are willing to commit to and pay for in the period covered by the IRP action plan. The IGCC analyses performed by the company support the view that a decision to add IGCC to the company's resource portfolio will not be driven by modeling considerations, but rather as an outcome of public policy debates and collaborative public-private development ventures such as the one recently announced by the Wyoming Infrastructure Authority and PacifiCorp.

Load Forecast

A number of parties requested additional explanation for why the March 2007 Utah load forecast shows a dip in the growth in 2008-2009 relative to the May 2006 forecast. The UCCS requested justification for why PacifiCorp relies on an expected (1 in 2) load forecast for planning, and inquires as to how planning to a 90% confidence interval would change the company's resource position and resource selection decisions. Regarding the higher load growth expected for Wyoming, the WRA expressed concern about committing resources to uncertain and volatile extractive industry loads, which account for the higher forecasted load growth. The UPSC requested the insertion of additional load forecast information in the IRP report.

Response: PacifiCorp accounts for load forecast error in its IRP by using a planning reserve margin. Planning to a 90 percent confidence internal would lessen the need to plan for unexpected load growth and, therefore, would likely reduce the level of planning reserve margin required by the company.

PacifiCorp is well aware of the volatile nature of extractive industry loads, and therefore applies a discount factor to the load forecasts contained in industrial customer service requests. Forecasts for the new Wyoming loads were reduced by 30 percent compared to estimates provided by customers. The load discount is based on rankings of the likelihood of occurrence of the customers' loads and the probability associated with that likelihood. Additionally, the company looks at the market conditions that will impact each industry, supply and demand in the industry, and other events that may impact the industry such as substitution impacts.

Concerning the requested load forecast information, PacifiCorp made the following report modifications to Chapter 4 and Appendix A:

- Data for 2006 was added to both the energy and coincident peak capacity forecasts tables in Chapter 4, as well as to each state table in Appendix A.
- A column was added to Table 4.5 in Chapter 4 that shows loads for the Southeast Idaho region.
- A new section, "Jurisdictional Peak Load Forecast," was added in Chapter 4 with information similar to that reported for the coincident peak.
- An explanation for the Utah load growth dip was added to Chapter 4 ("May 2006 Load Forecast Comparison").

Carbon Dioxide Regulatory Risk Analysis

The WRA cited a number of concerns with PacifiCorp's CO_2 risk modeling approach. First, they questioned the value of using a $0/ton CO_2 cost adder and cited the $8/ton medium adder case as also "remote over the long term." They advocate studying carbon costs in the range of plus or minus $30/ton. Second, they view the use of a year-2000 emissions cap under a cap-and-trade mechanism as unrealistic. Third, they believe that adding two coal resources by 2014 does not provide sufficient diversity to endure future carbon regulation. Fourth, they question PacifiCorp's treatment of CO_2 regulation as a scenario risk and propose that the company model it probabilistically. The UAE claims that PacifiCorp failed to capture the impact of higher gas prices and lower electricity demand attributable to potentially high carbon taxes. The RNP views PacifiCorp's greenhouse gas mitigation strategy as "insufficient for the task," and "is hardly an active strategy at all." The RNP also faults PacifiCorp for not modeling a portfolio that decreases overall CO_2 emissions, or that has no coal resources.

Response: PacifiCorp is required, via the Oregon IRP Standards and Guidelines, to assess environmental externality costs using a $0/ton CO_2 cost adder. Also, UPSC staff requested that the company include the $0 adder as part of a business-as-usual scenario case. The use of a single point estimate of around $30/ton, if that is what is being suggested, is not consistent with Oregon or Utah IRP guidelines that call for a number of specific adder values (in the case of Oregon) or a range of estimated external costs (in the case of Utah). PacifiCorp models a $38/ton adder (in 2008 dollars). Regarding the baseline cap and other assumptions for specifying a CO_2 regulatory framework, the company will revisit them as part of its next IRP process and as a result of the outcome of the Oregon Public Utility Commission proceeding on CO_2 risk in the IRP (Docket UM 1302). PacifiCorp does not understand WRA's point regarding the use of stochastic methods to model CO_2 regulatory risks. WRA supports stochastic analysis over scenario analysis, but then concedes that stochastic analysis is too complicated and should therefore be discounted or abandoned in favor of informed judgment. From this logic, PacifiCorp is not clear what modeling approach the WRA finds acceptable for conducting CO_2 risk analysis.

Regarding the claim that the company has not captured gas price risk due to higher carbon taxes, PacifiCorp notes that the gas price and electricity price forecasts used for the CO_2 cost adder scenarios account for the increased CO_2 adder values. See the text box titled "Modeling the Impact of CO_2 Externality Costs on Forward Electricity Prices" in the Environmental Externality Cost section of Chapter 6.

Finally, PacifiCorp updated Chapter 7 of the draft IRP report with a portfolio study that entailed constraining CEM system-wide resource selection to only those resources that could meet a California-style greenhouse gas emission performance standard. One of the resource choices was IGCC with carbon capture and sequestration.

Transmission

The UDPU had several transmission questions. First, they question whether transmission wheeling as a potential solution to transmission needs is appropriate given that it "fluctuates with the market". The UDPU also stated that the IRP draft does not address renewable portfolio standard (RPS) impacts on transmission planning or the National Governor's Conference positions on transmission planning and resources, and asks if these issues are being considered. Finally, they asked for clarification on the use of 500-megawatt blocks for specifying certain transmission paths in the CEM (Bridger-Ben Lomond; Mona-Utah North; Wyoming-Bridger East; Utah North-West Main; Utah South-Four Corners). The UAE expressed support for the use of transmission additions to delay supply-side resources, but was not clear if transmission was put on an equal footing with generation.

Response: PacifiCorp's view is that it is prudent to include all reasonable transmission options for consideration given the complexities associated with building transmission facilities. Regarding RPS requirements, the company is investigating the consequences of these new regulations.

Regarding specification of the above referenced transmission resources, these resources are considered as proxies for a variety of potential projects to support new generation and facilitate power transfers in the east control area. Specifying 500-megawatt blocks for a proxy transmission resource was an efficient method to express incremental transmission investment for the CEM to select.

Transmission resources were treated on a comparable basis with respect to generation resources. The CEM makes decisions to build generation or transmission units at a given resource site in a given year. The amortized cost of both transmission and generation capacity expansion is included in the model's PVRR minimization objective function.

Miscellaneous

Two parties, NWEC and the RNP, advocated that the company rely on an upper-tail measure of stochastic risk rather than risk exposure (stochastic upper-tail mean PVRR minus the overall stochastic mean PVRR for 100 Monte Carlo model iterations).

The RNP states that the IRP does not adequately consider the capital cost risks of pulverized coal plants, and cites one example of a coal plant construction estimate that increased by 50 percent over original estimates.

Regarding the Intermountain Power Plant Unit 3 project (IPP 3), the UDPU requested a status update and an indication of the company's current intentions regarding the project. The WRA also believes that an in-service date of 2012 for IPP3 or any other coal plant is unrealistic.

The UPSC requested detailed information on the company's commitment to invest $1.2 billion on cost-effective pollution control. Specific requests include the following:

- Explanation of "how and in what forum the Company plans to perform the cost-benefit analysis for these investments, and should such analysis be part of the Integrated Resource Planning evaluation?
- Does the $1.2 billion include mandatory requirements, i.e., mercury control on existing plants?
- Does it include those existing plant retrofit projects which are necessary for permit requirements to add new units at facilities?
- Clarify and provide a table showing the value, project description, and location of the investments.

Response: PacifiCorp has added the upper-tail mean along with the 95th percentile in the Chapter 7 tables that report stochastic risk measures for the risk analysis portfolios. The company notes that risk analysis portfolio rankings are generally invariant with respect to the stochastic risk measures.

PacifiCorp has been tracking construction costs for all new resource types, and has seen increases in costs for all resources. This fact is mentioned in Chapter 5. The company will use the bid information received for its Base Load Request For Proposal to help inform estimation of new resource capital costs for the 2007 IRP Update.

Regarding the status of IPP 3, PacifiCorp and the other Intermountain Power Plant Unit 3 (IPP 3) participants acknowledge that there are some air permit challenges by certain parties and contractual complications associated with Los Angeles Department of Water and Power that need to be resolved. PacifiCorp and the IPP 3 development team remain focused on working through these issues and intend to exercise their development right relating to construction of the facility. The IPP 3 development team is currently evaluating bids from major engineering procurement and construction contractors. IPP 3 remains a component in filling PacifiCorp's needs for low cost reliable resources, and the plant remains as a benchmark resource for 2012.

The UPSC's request for PacifiCorp's pollution control investment plans will be provided as a separate response.

CONTACT INFORMATION

PacifiCorp's IRP internet website contains many of the documents and presentations that support the 2003, 2004 and 2007 Integrated Resource Plans. To access it, please visit the company's website at http://www.PacifiCorp.com , click on the menu "News & Info" and select "Integrated Resource Planning".

PacifiCorp requests that any informal request be sent in writing to the following address or email address below.

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APPENDIX G – PERFORMANCE ON 2004 IRP ACTION PLAN

INTRODUCTION

This appendix summarizes the performance on the 2004 IRP action plan filed in January 2005. PacifiCorp provided an update of this action plan in November 2005 as part of the "2004 IRP Update" filed with state commissions in November 2005. The 2004 IRP Update action plan also incorporated updates to several action items in the 2004 IRP action plan. Table G.1 shows the progress of the original and updated action items listed in Table 5.2 of the 2004 IRP Update document (Chapter 5, page 46).

Table G.1 – Status Update on 2004 IRP Action Plan

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
1	Supply-Side	Renewables	FY 2006 - 2015	1,400	System	Wind	Continue to aggressively pursue cost-effective renewable resources through current and future RFP(s).	PacifiCorp has acquired 346 megawatts of the 400 megawatt target set for 2007, as of April 2007. The company plans to acquire all 1,400 megawatts by 2010, and to acquire an additional 600 megawatts from 2011 through 2013.
2	DSM	Class 2	FY 2006 - 2015	450 MWa	System	100 MW decrements at various load shapes	Use decrement values to assess cost-effective bids in DSM RFP(s). Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and up to an additional 200 MWa if cost-effective programs can be found through the RFP process.	• The company conducted a class 2 DSM decrement study for the 2007 IRP. To address risk, this study used stochastic simulation with an \$8/ton CO_2 adder. PacifiCorp also increased the number of load shapes from eight to twelve. • The 2005 DSM RFP to procure Class 1, 2 and 3 resources was issued according to the action plan in the 2004 IRP (reference Table 9.3). The RFP was structured to solicit proposals for both specific resources types: a comprehensive residential equipment and service program as well as an "all comers" request for each resource type. • The Home Energy Savers program was filed and approved in 2006 in Idaho, Washington and Utah and is being proposed in California and Wyoming in 2007. On March 20, 2007, the Utah Public Service Commission approved modifications to the

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
								2007 Energy Star New Homes Program and in April 2007 extended the Cool Cash air conditioner efficiency program. • The company also accepted a proposal to enhance business program penetration of the new construction market. In addition, one program proposal from the 2005 DSM RFP is still under consideration. It will be evaluated further using updated valuation information derived through the 2007 IRP planning process as well as results from the system-wide DSM potential study results due in June 2007.
3	Distributed Generation	CHP	FY 2010 (summer of CY 2009) and FY 2013 (CY 2012)	n/a	System	Two 45 MW units using NREL cost estimates	Include CHP as eligible resources in supply-side RFPs.	Continue to purchase CHP output as Qualifying Facilities (QF) pursuant to PURPA regulations. The 2007 preferred portfolio contains an additional 100 MW of CHP resources, cited in 2007 IRP action plan item no. 5.
4	Distributed Generation	Standby Generators	FY 2010 (summer of CY 2009) and FY 2013 (CY 2012)	n/a	Utah	75 MW in Utah	Include a provision for Standby Generators in supply-side RFPs. Investigate, with Air Quality Officials, the viability of this resource option.	The final Base Load RFP does not contain an East side stand-by generation resource exception due to Utah Division of Air Quality regulations on diesel generation emissions standards. PacifiCorp will continue to investigate alternatives for stand-by generators as a resource. PacifiCorp met with Portland General Electric to discuss their stand-by generation program.

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
5	DSM	Class 1	FY 2009 (summer of CY 2008)	50	Utah	Irrigation Load Control	Procure cost-effective summer load control program in Utah by the summer of 2008.	The company launched a commercial lighting control program (Load Lightener) in Utah in February 2005. However, the program was terminated in August 2006 due to poor program performance. The company expanded the Idaho irrigation load management program and extended the Idaho irrigation load management program into Utah in the spring of 2007, and continues to investigate the possible expansion of Utah's air conditioner load control program beyond 100 MWs (at the generator). In addition, the company is still evaluating, within the 2007 planning process, two other Class 1 proposals received through the 2005 DSM RFP. Like the Class 2 proposal, the company will utilize the system-wide DSM potential study results to help further assess the viability of the remaining proposals.
6	DSM	Class 1	FY 2009 (summer of CY 2008)	50	OR/WA/ CA	Irrigation Load Control	Procure cost-effective summer load control program in Oregon, Washington, and/or California by the summer of 2008.	The 2005 DSM RFP generated Class 1 load control proposals targeting our western system. The proposals were of various sizes and were significantly more expensive than anticipated. The proposals underwent further analysis within the 2007 IRP modeling process and were determined not to be cost-effective. However, the 2007 IRP modeling did select the lesser cost irrigation load management pro-

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
								gram which the company intends to investigate implementing beginning as early as 2010.
7	Transmission	Path-C Upgrade	FY2011 (summer of CY 2010)	300	ID / UT	Path-C Upgrade	Pursue upgrade of transfer capability from Idaho to Utah.	Path C transmission service requests have been completed for the system impact studies and are currently under the Facility Study phase. Grid West was dissolved as of June 2006. Other regional entities continue to pursue regional transmission planning initiatives. Please see Chapter 3 for additional transmission related topics.
8	Supply-Side	Coal resource	FY 2013 (summer of CY 2012)	600	Utah	Pulverized Coal Plant	Procure a high capacity factor resource in or delivered to Utah by the summer of CY 2012.	The Base Load RFP was issued on April 5, 2007 for up to 1,700 MW for delivery in 2012, 2013, and/or 2014. The company is currently in the bidder submission phase of the RFP process. The RFP contains two benchmark coal plants and an IGCC option for bidders. Resources for 2012 and 2014 are being requested with exceptions for load curtailment and Qualifying Facility contracts.
9	Transmission	Regional Transmission	FY 2013 and beyond	n/a	System	Transmission from Wyoming to Utah	Continue to work with other regional entities to develop Grid West. Continue to actively participate in regional transmission initiatives (e.g. RMATS, NTAC)	PacifiCorp is engaged in a number of regional transmission planning initiatives intended to address transmission issues and opportunities. WECC recently launched the Transmission Expansion Planning Policy Committee (TEPPC) to address interconnection-wide transmission expansion planning. Grid West was dissolved as of June 2006. A group called the Northern

Action Item	Addition Type	Resource Type	Timing	Size (Rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	2004 IRP Action Plan Description	Status
								Tier Transmission Group was formed to facilitate regional planning in the absence of Grid West and the Rocky Mountain Area Transmission Study (RMATS). Please see Chapter 3 for additional transmission related topics.
10	IRP Process	Modeling	2007 IRP	n/a	n/a	n/a	Incorporate Capacity Expansion Model into portfolio and scenario analysis.	PacifiCorp placed the Capacity Expansion Module (licensed by Global Energy Decisions Inc.) into full production for the 2007 IRP process. See Chapters 6 and 7 for more information on how this tool was used in the 2007 IRP.

APPENDIX H – DEFERRAL OF DISTRIBUTION INFRASTRUCTURE WITH CUSTOMER-BASED COMBINED HEAT AND POWER GENERATION

INTRODUCTION

As part of Oregon Order 06-029, PacifiCorp was asked to examine the potential for customer-based high-efficiency combined heat and power (CHP) resources to defer investment in the distribution system to meet load growth. The specific situation the company was ordered to examine was a case where a customer utilizing CHP, sized to exactly meet the customer load, would be connected to the distribution system as normal, but no additional infrastructure would be added to accommodate the additional load. In the event of an outage to the generation, the customer would be served by PacifiCorp's distribution system, as long as capacity was available; if this outage occurred at a time where the distribution infrastructure was incapable of serving the additional load for whatever reason, the customer would be automatically disconnected.

The intent of this appendix is to first determine what distribution infrastructure deferrals would be possible for an interruptible customer with on-site generation as described above, and then to compare the cost of those deferrals to a traditional customer taking firm service and having no on-site generation. For the purposes of the comparison, it is assumed that five megawatts of customer load is to be added to PacifiCorp's west control area 12.5 kilovolt distribution system (either a new load or a customer adding load).

TRADITIONAL CONNECTION

Extending service to a five megawatt customer to the company's distribution system is a typical industrial new connection for PacifiCorp, a request which occurs many times per year. Generally a customer receives an allowance for their connection facilities equal to one year's expected revenue; any expenditure beyond this is an out-of-pocket expense for the customer. For a customer of this size, these connection requirements typically range from $50,000 to $150,000, not inclusive of upstream reinforcements necessary to accommodate new load. The expected revenue for a five megawatt, primary-metered customer ranges from $400,000 to $600,000 per year, which means that usually all of the cost is borne by PacifiCorp. The upstream reinforcements can range from $500,000 for new feeder infrastructure to more than $2,500,000 if an additional substation is required. These are also at the company's expense.

The total cost of adding a new five megawatt customer is estimated to range from $550,000 to $2,650,000 in this example. All of these connection expenses are considered capital improvements and are depreciated over 50 to 60 years, depending on the type of facility.

GENERATION CONNECTION

If a customer decides to serve its electricity needs with an on-site generating facility, along with being interrupted when their own generating facility is down, then the company would not expect any revenues. Therefore, the company would not pay any connection costs for this customer and would save $50,000 to $150,000 of interconnection costs describe above.

Additionally, because this customer would be interruptible if the existing distribution infrastructure could not serve the customer for some reason (under-voltage, over-current, etc.) during a generator outage, no additional infrastructure would be necessary. This may allow the company to defer the $500,000 to $2,500,000 investment previously identified, depending on the current loading levels on the feeder. For example, PacifiCorp rates its 12.5 kilovolt circuits for approximately ten megawatts, or twice the load that is expected to be added as a result of this customer connection. Therefore, any feeder already loaded to 50 percent or more of its rating would need to be upgraded in order to provide traditional service to this particular customer. Feeders loaded below this threshold would not require upgrade. Examining Oregon's feeder population, we find that about 61 percent of PacifiCorp Oregon circuits are currently loaded at or above 50 percent. If the five megawatt customer were to be located on one of these feeders, then there could be deferred investment of $500,000 to $2,500,000. If the five megawatt customer were to be located on one of these feeders, then there could be deferred investment of $500,000 to $2,500,000. PacifiCorp would not realize any additional capital investment savings for customers located on the other 39 percent of feeders.

CONCLUSION

The comparison above shows that a five megawatt load, coupled with a five megawatt customer-sited generation unit (customer-owned or not) located on a typical 12.5 kilovolt feeder in Oregon can potentially offset estimated connection costs of $50,000 to $150,000 under current line extension policies. In addition, there may be an opportunity to avoid infrastructure costs, at an estimated amount of $500,000 to $2,500,000. These savings would only be available if the customer agreed to be interrupted when their generation is reduced or off-line, and the distribution system is not capable of being used to serve their load. Actual savings, if any, from a customer in a situation similar to the one described in this example, would be based on their particular circumstances.

APPENDIX I – IRP REGULATORY COMPLIANCE

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 has expanded since then to incorporate the consideration of risk, uncertainty, and environmental externality costs into the resource evaluation framework. Planning rules were also intended to require utilities to involve regulators and the general public in the planning process prior to making resource decisions.

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 the 2007 IRP complies with the various state commission IRP Standards and Guidelines, 2004 IRP acknowledgement requirements, and other commission decisions. Included at the end of this appendix are the following tables:

- Table I.1 – Provides an overview and comparison of the rules in each state for which IRP submission is required.[3]
- Table I.2 – Provides a description of how the 2004 IRP acknowledgement requirements and other commission requests were addressed.
- Table I.3 – Provides an explanation of how this plan addresses each of the items contained in the new Oregon IRP guidelines issued in January 2007.
- Table I.4 – Provides an explanation of how this plan addresses each of the items contained in the Utah Public Service Commission IRP Standard and Guidelines issued in June 1992.

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 consultation between 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

[3] California and Wyoming requirements are not summarized in Table I.1. The Wyoming requirements are discussed in the chapter text. California guidelines exempt a utility with less than 500,000 customers in the state from filing an IRP.

approach. The public input process for this IRP, described in Volume 1, Chapter 2, as well as in Appendix F, fully complies with the IRP Standards and Guidelines.

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

To fill any gap between changes in loads and existing resources, the IRP evaluates all available resource options, as required by state commission rules. These resource alternatives include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapters 6 and 7, meets this requirement and includes the impact to system costs, system operations, supply and transmission 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 Interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described at a high level in Chapter 2 and in greater detail in Chapter 6.

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual CO_2 emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Chapter 7.

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan (See Chapter 8). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. Appendix G provides a progress report that relates the 2007 IRP Action Plan with those provided in the 2004 IRP and 2004 IRP Update.

The 2007 IRP and the related 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 serves only 42,000 customers in the most northern parts of the state. PacifiCorp filed for and received an exemption on July 10, 2003.

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 2007, and fully addresses the above report components. The IRP also evaluates DSM using a load decrement approach, as discussed in Chapters 6 and 7. 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 new planning guidelines issued in January 2007 (Order No. 07-002). These guidelines supersede previous ones, and many codify analysis requirements outlined in the Commission's acknowledgement order for PacifiCorp's 2004 IRP.

The Commission's new IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), and resource acquisition (Guideline 13). Consistent with the earlier guidelines (Order 89-507), the Commission notes that acknowledgement does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table I.3 provides considerable detail on how this plan addresses each of the requirements.

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"). Table I.4 documents how PacifiCorp complies with each of these standards.

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), and the rule amendment issued on January 9, 2006 (WAC 480-100-238, Docket No. UE-030311). 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."

The rule amendment also now requires PacifiCorp to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, the resource assessment method, and timing and extent of public participation. PacifiCorp filed a work plan with the Commission on February 21, 2006, and had a follow-up conference call with WUTC staff to make sure the work plan met staff expectations.

Finally, the rule amendment now requires PacifiCorp to provide an assessment of transmission system capability and reliability. This requirement was met in this IRP by modeling the company's current transmission system along with both generation and transmission resource options as part of its resource portfolio analyses. These analyses used such reliability metrics as Loss of Load Probability and Energy Not Served to assess the impacts of different resource combinations on system reliability. The stochastic simulation and risk analysis section of Chapter 7 reports the reliability analysis results.

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 I.1 – Integrated Resource Planning Standards and Guidelines Summary by State

Topic	Oregon	Utah	Washington	Idaho
Source	Order 89-507 *Least-cost Planning for Resource Acquisitions,* April 20, 1989. Order No. 07-002, *Investigation Into Integrated Resource Planning*, January 8, 2007.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking,* January 9, 2006 (Docket # UE-030311)	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.
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.
Frequency	Plans filed biennially. Interim reports on plan progress also required (informational filing only). Order 07-002 requires IRP filing within two years of its previous IRP acknowledgement order.	File biennially.	File biennially.	RMP to be filed at least biennially. Conservation reports to be filed annually.
Commission response	Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgement order is issued. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP *acknowledged* if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.

Topic	Oregon	Utah	Washington	Idaho
Process	The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07-002 requires that the utility present IRP results to the OPUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing. 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. For the amended rules issued in January 2006, PacifiCorp is required to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation.	Utilities to work with Commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.
Focus	20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.	20-year plan, with short-term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	20-year plan, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at "lowest reasonable" cost to utility and ratepayers. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, and environmental risks, must be considered.	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.
Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the	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.	The plan shall include: • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electri-	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options;

Topic	Oregon	Utah	Washington	Idaho
	long-run public interest. • The plan must be consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Identify acquisition strategies for action plan resources, assess advantages/disadvantages of resource ownership versus purchases, and identify benchmark resources considered for competitive bidding. • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Avoided cost filing required within 30 days of acknowledgement.	• 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.	cal end-uses. • An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. • Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability (Added per amended rules issued in January 2006). • A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using "lowest reasonable cost" criteria. • Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. • All plans shall also include a progress report that relates the new plan to the previously filed plan.	• Contingencies for upgrading, optioning and acquiring resources at optimum times; • Report on existing resource stack, load forecast and additional resource menu.

Table I.2 – Handling of 2004 IRP Acknowledgement and Other IRP Requirements

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
ID	Staff recommends that PacifiCorp continue to evaluate and investigate IGCC in its next IRP. (Acceptance of Filing, Case No. PAC-E-05-2, p. 6)	PacifiCorp incorporated various IGCC resources, distinguished by location and technology configuration (including CO_2 capture and sequestration), in its capacity expansion optimization and stochastic modeling studies. Chapter 7 describes the IGCC modeling results.
ID	As we indicated in our acceptance of the Company's 2003 Electric IRP filing, in addition to being apprised through periodic status reports of supply resources the Company is actually building or contracting for and demand side programs the Company is implementing, the Commission expects to receive periodic updates as to the Company's specific plans for issuing requests for proposals (RFPs). (Acceptance of Filing, Case No. PAC-E-05-2, p. 7)	PacifiCorp provided the Idaho Public Utility Commission procurement updates on April 12 and August 30, 2006, and plans to provide them on a quarterly basis.
OR	Use decrement values to assess cost-effective bids in DSM RFP(s). Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth, and as approved by each State's Commission. (Action Item 1 revision, OPUC Order 06-029, p. 60)	See the "Class 2 Demand-side Management Decrement Analysis" section in Chapter 7 for updated decrement values. See the "Existing Resources" section of Chapter 4 for an update on the progress of Class 2 DSM programs, as well as Appendix G, "Action Plan Status".
OR	Execute an agreement with the Energy Trust of Oregon, as soon as possible, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable timely completion of resource agreements with the recent extension of the federal production tax credit. (Additional Action Item, OPUC Order 06-029, p. 60)	A master agreement to fund the above-market costs of new renewable energy resources was signed on April 6, 2006.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
OR	For the next IRP or Action Plan, develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach. (Additional Action Item, OPUC Order 06-029, p. 60)	PacifiCorp used Class 1 DSM proxy supply curves, developed by Quantec LLC, for portfolio optimization modeling using the Capacity Expansion Module. See Appendix B for the complete Quantec DSM study. Chapter 5 outlines the supply curves used in the CEM. For Class 2 DSM, the company chose to continue using the decrement approach for the 2007 IRP, but enhanced it by adopting stochastic simulation to capture risk. PacifiCorp's plan to use decrement analysis was presented and discussed at the February 10, 2006 technical workshop on demand-side management.
OR	For the next IRP or Action Plan, assume existing interruptible contracts continue unless they are not renegotiable or other resources would provide better value. (Additional Action Item, OPUC Order 06-029, p. 60)	PacifiCorp adopted the assumption that existing interruptible contracts are extended until beyond the end of the 20-year IRP study period.
OR	For the next IRP or Action Plan, assess IGCC technology in a location potentially suitable for CO_2 sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties, including market prices and CO_2 regulation. (Additional Action Item, OPUC Order 06-029, p. 61)	PacifiCorp included several IGCC plant configurations and locations as resource options in its "alternative future" scenario modeling, including one with carbon capture and sequestration. IGCC resources were also included in risk analysis portfolios for stochastic simulation. See "Resource Options" in Chapter 5 for IGCC cost and performance characteristics. See Chapter 7 for IGCC modeling results.
OR	For the next IRP or Action Plan, analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission. (Additional Action Item, OPUC Order 06-029, p. 61)	PacifiCorp included various transmission resources in its capacity optimization model. For a CEM sensitivity study, the company included a proxy resource representing the Frontier Line project, reflecting a strategy to access markets in California and the southwest U.S. See "Resource Expansion Alternatives" in Chapter 5 for details on the transmission resources modeled, and Chapter 7 for modeling results.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
OR	Conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in PacifiCorp's service area over the IRP study period, and assess how the Company's base and planned programs compare with the cost-effective amounts determined in the study. (New IRP requirement, OPUC Order 06-029, p. 61)	Due to the timing of OPUC's 2004 acknowledgment Order (in January 2006), and as agreed to by OPUC staff, this requirement is being met via the MEHC commitment to perform a multi-state DSM potentials study to be completed by June 2007. Development and use of Quantec's proxy DSM supply curves was intended as a compromise strategy until the DSM potentials study becomes available for use in the next IRP.
OR	Determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply-side options. (New IRP requirement, OPUC Order 06-029, p. 61)	PacifiCorp incorporated supply curves into its portfolio modeling for the following Class 3 DSM resources: Curtailable Rates, Demand Buyback, and Critical Peak Pricing. See Chapter 4 and Appendix B for details.
OR	Evaluate loss of load probability, expected unserved energy, and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. (New IRP requirement, OPUC Order 06-029, p. 61)	PacifiCorp included these supply reliability metrics as part of its stochastic portfolio risk analysis. The Planning and Risk Module (PaR) 12-percent capacity reserve margin sensitivity study included the maximum available amount of Class 3 DSM as indicated by the Quantec proxy supply curves.
OR	Evaluate alternatives for determining the expected annual peak demand for determining the planning margin — for example, planning to the average of the eight-hour super-peak period. (New IRP requirement, OPUC Order 06-029, p. 61)	This requirement was met via a Capacity Expansion Module sensitivity analysis. See Chapter 7 for a results summary.
OR	Evaluate, within portfolio modeling, the potential for reducing costs and risks of generation and transmission by including high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas. (New IRP requirement, OPUC Order 06-029, p. 61)	CHP and aggregated dispatchable customer standby generation were modeled as part of a 12% planning reserve margin sensitivity analysis using PaR. See Chapter 7 for a results summary.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
OR	Evaluate the potential value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment. (New IRP requirement, OPUC Order 06-029, p. 61)	PacifiCorp conducted a study of distribution system investment deferral potential assuming a 5-megawatt CHP interconnection project in the company's west control area. See Appendix H.
OR	If pumped storage technology becomes a viable resource option in the future, the Commission expects PacifiCorp to analyze the associated environmental costs that ratepayers might incur. (OPUC Order 06-029, p. 53)	Pumped storage was not evaluated in this IRP due to an expected commercial operations date beyond the 10-year acquisition horizon.
OR	Analyze planning margin cost-risk tradeoffs within stochastic modeling of portfolios. If feasible, analyze the cost-risk tradeoff of all portfolios at various planning margins. If not feasible, build all portfolios to a set planning margin, test them stochastically, and adjust top-performing portfolios to higher and lower planning margins for further stochastic evaluation. (New requirement, OPUC Order 06-029, p. 61)	PacifiCorp's approach to meeting this requirement was to use the CEM to derive optimal portfolios using planning reserve margins set at 12%, 15%, and 18%. To determine the stochastic impacts, these same portfolios were run with the PaR model in stochastic mode. PacifiCorp also simulated risk analysis portfolios derived from CEM runs constrained with both 12% and 15% planning reserve margins.
OR	For the next IRP or Action Plan, analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's cost to integrate wind resources. (Additional Action Item, OPUC Order 06-029, p. 60)	Proxy wind projects were included as resource options in CEM runs, and included in stochastic simulations for evaluating risk analysis portfolios. See Appendix J for the results of PacifiCorp's updated studies on wind integration costs, determination of cost-effective wind resources, and wind capacity planning contribution. Appendix J also includes a discussion on the effect of fuel type on wind integration costs. Chapter 7 outlines stochastic simulation results for portfolios with incremental wind additions.
OR	We also expect the Company to fully explore whether delaying a commitment to coal until IGCC technology is further commercialized is a reasonable course of action. (OPUC Order 06-029, p. 51)	PacifiCorp developed and evaluated a portfolio that excludes pulverized coal as a resource option. PacifiCorp also evaluated two additional portfolios that were specified by OPUC staff. These two portfolios, each developed according to 12% and 15% planning reserve

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
		margins respectively, (1) defer pulverized coal until after 2014, (2), include an IGCC plant in 2014, and (3) include 600 MW of additional wind. The portfolio evaluation results are summarized in Chapter 7.
UT	We direct the Company to structure the public input process to allow sufficient time for discussion of issues raised by parties and to address relevant issues raised in this IRP. (Utah PSC, Docket No. 05-2035-01, p. 21)	PacifiCorp organized the public meeting schedule to front-load discussions on key modeling approaches and issues (DSM, renewables, CO_2 analysis, etc.). The company also distributed papers on scenario analysis and risk analysis portfolio development to provide interim information prior to public meetings. See Chapter 2, "Stakeholder Engagement".
UT	We believe a comprehensive annual update to the IRP between the biennial IRP filings should continue. (Utah PSC, Docket No. 05-2035-01, p. 21)	PacifiCorp will continue with biennial IRP updates, since this is now a requirement under the new Oregon PUC.
UT	We find reasonable the Division's request for semi-annual updates of the load and resource balance. (Utah PSC, Docket No. 05-2035-01, p. 21)	PacifiCorp provided a semi-annual update of its load and resource balance at the April 20, 2007 IRP public meeting.
UT	We direct the Company to investigate improving the transparency of the IRP modeling to increase confidence in the results. (Utah PSC, Docket No. 05-2035-01, p. 21)	PacifiCorp provided stakeholders with a detailed modeling plan and scenario/risk analysis methodology, and solicited comments on them prior to the start of IRP modeling. Model results documentation has been distributed at the conclusion of the key portfolio analysis milestones—evaluation of CEM runs, selection of risk analysis portfolios for stochastic simulation, and selection of the preferred portfolio.
UT	Include a section that specifically addresses the PURPA Fuel Sources Standard in all future Integrated Resource Plans. ("Determination Concerning The PURPA Fuel Sources Standard", Docket No. 06-999-03)	A section on fuel source diversity is included in Chapter 8, "Action Plan".
UT	Per agreement with Utah Commission staff, include a 20-year forecasted average heat rate trend for the company's fossil fuel generator fleet that includes IRP resources and currently planned retirements.	A section titled, "Forecasted Heat Rate Trend," is included in Chapter 7.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
WA	The recommended reserve margin is greatly influenced by the nature, mix, and capacity of available resources, and risks associated with any particular resource. Thus, the company should quantify the reserve margin in a way that incorporates risks posed by each specific resource. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 10)	PacifiCorp outlined at IRP public meetings (January 13 and May 10, 2006) an innovative statistical approach for determining the amount of an additional resource needed to a keep a utility system's Loss of Load Probability (LOLP) constant. This method, which accounts for resource-specific reliability characteristics, was applied in this IRP to determine the Peak Load Carrying Capability for wind resources. PacifiCorp is evaluating this approach for applicability to all resource additions modeled in the IRP.
WA	The Commission expects PacifiCorp's next plan to further refine wind energy's reserve value and effects on the stability of power systems. PacifiCorp should also work to minimize any qualifications around its estimates of the value of wind. The Commission encourages PacifiCorp to continue to explore renewable resources, and to develop these resources when economic and compatible with system objectives. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 7)	See Appendix J for the results of PacifiCorp's updated studies on wind integration costs, determination of cost-effective wind resources, and wind capacity planning contribution. Chapter 7 outlines stochastic simulation results for risk analysis portfolios with different amounts and timing of wind resources. PacifiCorp's preferred portfolio includes 2,000 megawatts of renewables, as opposed to 1,400 megawatts for the original MEHC renewables commitment.
WA	We encourage PacifiCorp to further refine its approach by developing load curves for its west-side control area. The company should explicitly look at the load shapes for residential heating and lighting to assess the potential for DSM and energy efficiency measures in Washington. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 7)	PacifiCorp evaluated its load shapes for Class 2 DSM decrement calculation, and determined that residential lighting load shapes for the west and east control areas should be added. These load shapes are reported in Chapter 5. Decrement results for the new load shapes are reported in Chapter 7, "Class 2 DSM Decrement Analysis".
WA	In the Commission's letter regarding PacifiCorp's 2002 IRP, the company needs to explore ways to quantify the risk preferences of customers and shareholders. Only by understanding its risks and the risk preferences of stakeholders can PacifiCorp rank and prioritize alternative resource portfolios. (WUTC IRP Acknowledgment	PacifiCorp has relied on the public process (including the 2004 IRP stakeholder satisfaction survey conducted in 2005) to solicit customer and other stakeholder views on what risk factors to consider and how to address them in resource portfolio evaluation. PacifiCorp's uncertainty and risk analysis framework for the 2007 IRP reflects this input. For example, the company used risk metrics and

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
	Letter, Docket UE-050095, p. 7)	risk trade-off analysis to address such criteria as overall portfolio cost, supply reliability, and rate volatility impact, among others.
WA	The company should consider the costs and advantages of implementing a multi-objective function optimization [model] as part of its next plan. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 8)	PacifiCorp and WUTC staff participated in a conference call on April 18, 2006, pertaining to this issue and others identified in the WUTC IRP acknowledgment letter. PacifiCorp indicated that it was not aware of a commercially available multi-objective optimization modeling tool suitable for integrated resource planning.
WA	The company needs to develop avoided costs for general purpose energy and capacity in both the short and long-term. Furthermore, PacifiCorp should derive an avoided cost schedule for transmission and distribution resources. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 8)	PacifiCorp makes avoided cost filings after each IRP is filed. The company will consider expanding its avoided cost schedules to cover the areas identified by the WUTC.
WA	PacifiCorp's plan does not directly consider the price influence of various energy commodities upon on another. PacifiCorp should consider whether its plan would benefit from linking gas, coal and oil prices through a high-level market fundamentals tool. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 8)	PacifiCorp and WUTC staff participated in a conference call on April 18, 2006, pertaining to this issue and others identified in the WUTC IRP acknowledgment letter. The company stated that its fundamentals modeling tool, MIDAS, addresses energy commodity interactions. This topic is addressed in Appendix A in the discussion on commodity prices.
WA	The Commission encourages PacifiCorp to investigate using the most up-to-date models and tools, including, for example, those commonly used by other utilities such as the AURORA production cost and dispatch model. Also, additional detail regarding the algorithms and mathematics of the modeling tools would improve the value of the report. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 4)	PacifiCorp routinely evaluates other computer models for applicability to the IRP process, including AURORA and its competitor products. PacifiCorp conducted an IRP benchmarking study in 2005 in which electric utility use of computer models was investigated. This study was included as Appendix C of the 2004 IRP Update. Regarding the recommendation to disclose additional details on model algorithms and mathematics in the IRP, the company notes that its modeling tools are covered under vendor license agreements that prohibit distribution of proprietary material except when required under regulatory commission order.

State	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2007 IRP
WA	The Company used the MIDAS model to compute variations off the base forecast. The plan did not document the assumptions, model structure or reliability of PIRA or MIDAS forecasts. PacifiCorp needs to allow access to the models used to forecast prices to Commission staff. Without knowledge of how the models operate staff cannot evaluate the fundamentals forecast model used by PIRA or other agencies. The Commission notes that other utilities in our jurisdiction provide staff access to representatives of the gas supply and price consultants to discuss the mechanics of studies, data source, and policy assumptions used in forecast models. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 5)	PacifiCorp proposes to institute a series of technical workshops on fundamentals modeling for the next IRP, similar to the load forecasting workshops held for the 2004 and 2007 IRPs. PacifiCorp will work with Commission staff to provide knowledge of PacifiCorp's models and associated data and access to the company's consultants and studies upon request and under appropriate confidentiality conditions where necessary.
WA	Increasingly volatile natural gas prices have made short-term price predictions based on fundamentals modeling less reliable. Therefore, price forecasts generated from non-fundamental models and the forwards market should support or supplement the price forecasts used in the two-year actions plan. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 5)	PacifiCorp and WUTC staff participated in a conference call on April 18, 2006, pertaining to this issue and others identified in the WUTC IRP acknowledgment letter. PacifiCorp noted that it uses market information for the first six years of forward gas prices.
WA	Given the importance of individual state policies in PacifiCorp's resource acquisition decisions, the Commission specifically requests that the Company model and evaluate the effects of state specific policies on its decisions to acquire certain resources. (WUTC IRP Acknowledgment Letter, Docket UE-050095, p. 10)	PacifiCorp and WUTC staff participated in a conference call on April 18, 2006, pertaining to this issue and others identified in the WUTC IRP acknowledgment letter. The Commission's concern was focused on state economic development policies in other states. PacifiCorp agreed to address this issue in narrative fashion given that state economic development initiatives would impact the load forecast and not resource modeling directly. See the load forecasting section entitled, "Treatment of State Economic Development Policies" in Appendix A.

Table I.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
Guideline 1. Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, and transmission. Chapters 5 and 6 document how PacifiCorp developed and assessed these technologies. In brief, the company used a combination of PacifiCorp generation staff expertise, Electric Power Research Institute Technical Assessment Guide (TAG®) data, and capacity expansion optimization modeling to assess these technologies. Generation resource types were initially assessed by PacifiCorp's generation experts, and a list that captures the salient technology types and configurations was assembled (Chapter 5, Tables 5.1 and 5.2). Decisions on what generation resources to include in the Capacity Expansion Module was based on generation staff recommendations and the need to limit resource options to a manageable number based on model constraints and run-time considerations. (The company notes that the need to place restrictions on the number of resource options is a common IRP problem for utilities that use such optimization models for long-term planning.) Based on the modeling lessons learned for this IRP and the anticipated expansion of resource options arising from the DSM potentials study due in June 2007, PacifiCorp intends to explore new resource screening methods to accommodate a broader range of technologies while meeting the requirement to assess technologies on a 'consistent and comparable basis."
1.a.2	All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource	PacifiCorp considered various combinations of fuel types, technologies, lead times, in-service dates, durations, and locations for

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	both capacity expansion optimization modeling (deterministic risk modeling via scenario analysis) as well as stochastic risk modeling. Chapters 6 and 7 document the modeling methodology and results, respectively. Chapter 5 describes resource attributes in detail. The range of resource attributes accounted for in stochastic risk analysis is indicated in Chapter 7, Tables 7.17 and 7.31 through 7.35. These tables list the resources included in the risk analysis portfolios.
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company used the Electric Power Research Institute's Technical Assessment Guide (TAG®) to develop generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used Quantec LLC's proxy supply curves, which applied a consistent methodology for determining technical, market, and achievable DSM potential. All portfolio resources were evaluated using the same sets of inputs. These inputs are documented in Appendix A.
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its after-tax WACC of 7.1 percent to discount all cost streams.
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	PacifiCorp fully complies with this requirement. Each of the sources of risk identified in this guideline is treated as a stochastic variable in Monte Carlo production cost simulation. See the stochastic modeling methodology section in Chapter 7.
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	PacifiCorp evaluated additional risks and uncertainties, including resource capital costs, coal prices, and the level of DSM achievable potential. See Chapter 6 for a discussion on what variables were modeled for scenario and stochastic risk analysis.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered. See Chapter 7 for the company's portfolio risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	PacifiCorp fully complies. Chapter 6 provides a description of the PVRR methodology.
1.c.3.1	To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail PVRR (mean of highest five Monte Carlo iterations), risk exposure (upper-tail mean PVRR minus overall mean PVRR), and 95th percentile stochastic PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on costs and risks of physical and financial hedging is provided in Chapter 5.
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 7 summarizes the results of PacifiCorp's cost/risk tradeoff analysis, and describes what criteria the company used to determine what resource combinations provide an appropriate balance between cost and risk.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and expected state and federal energy policies in portfolio modeling. Chapter 7 describes the decision process used to derive portfolios, which includes consideration of state resource policy directions.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	PacifiCorp fully complies with this requirement. Chapter 2 provides an overview of the public process, while Appendix F documents the details on public meetings held for the 2007 IRP.
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	Both IRP volumes provide non-confidential information the company used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email.
2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PacifiCorp distributed a draft IRP document for external review on April 20, 2007.
Guideline 3: Plan Filing, Review, and Updates		
3.a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	This Plan complies with this requirement.
3.b	The utility must present the results of its filed plan to the Commission at a public	PacifiCorp will adhere to this guideline.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	meeting prior to the deadline for written public comment.	
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	Not applicable
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	Not applicable
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable
3.f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	Not applicable
3.g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: 1. Describes what actions the utility has taken to implement the plan; 2. Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and 3. Justifies any deviations from the ac-	Not applicable

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	knowledged action plan.	
Guideline 4. Plan Components (at a minimum, must include…)		
4.a	An explanation of how the utility met each of the substantive and procedural requirements	The purpose of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions	PacifiCorp developed low, medium, and high load growth forecasts for scenario analysis using the Capacity Expansion Module. Stochastic variability of loads was also captured in the risk analysis. See Chapter 6 for a description of the load forecast data and Chapter 7 for scenario and risk analysis results.
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested	This Plan complies with the requirement. See Chapter 4 for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies, as mentioned in Appendix A (Transmission System).
4.d	For gas utilities only	Not applicable
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology	Chapter 5 identifies the resources included in this IRP, and provides their detailed cost and performance attributes (see Tables 5.1 through 5.4).
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs	In addition to incorporating a planning reserve margin for all portfolios evaluated, the company used several measures to evaluate relative portfolio supply reliability. These are described in Chapter 6. PacifiCorp conducted several sensitivity studies to determine the cost/risk tradeoff of different planning reserve margin levels. These studies, and resulting company conclusions, are documented in Chapter 7.
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered	Appendix A and Chapter 6 describe the key assumptions and alternative scenarios used in this IRP.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system	This Plan documents the development and results for 56 portfolios evaluated in this IRP (Chapter 7).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties	Chapter 7 presents the deterministic and stochastic portfolio modeling results, and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Chapter 7 provides tables and charts with performance measure results, including rank ordering as appropriate.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	PacifiCorp fully complies with this guideline. See the responses to 1.b.1 and 1.b.2 above.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is presumed to have no inconsistencies.
	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Chapter 8 presents the 2007 IRP Action Plan.
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and	PacifiCorp evaluated proxy transmission resources on a comparable basis with respect to other proxy resources in this IRP. For example, the Capacity Expansion Module was allowed to select the most economic transmission options given other supply and demand-side resource options selected by the model. Fuel transportation costs were

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	factored into resource costs.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	A multi-state demand-side management potentials study is scheduled for completion in June 2007.
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	A discussion on the treatment of conservation programs (Class 2 DSM) is included in Chapter 6, "Oregon Public Utility Commission Guidelines for Conservation Program Analysis in the IRP."
6.c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	See the response for 6.b above.
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (Class 3 DSM) on a consistent basis with other resources in its CEM alternative future scenario analysis, as well as conducted a sensitivity analysis using the Planning and Risk Module. See Chapter 7.
Guideline 8: Environmental Costs		
8	Utilities should include in their base-case analyses the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in	This IRP fully complies with the CO_2 compliance cost analysis requirements in Order No. 93-695. Modeling results for the CO_2 cost adder levels are reported in Chapter 7.

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
	Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.	
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	PacifiCorp continues to plan for load for direct access customers.
Guideline 10: Multi-state Utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2007 IRP conforms to the multi-state planning approach as stated in Chapter 2.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	PacifiCorp fully complies with this guideline. See the response to 1.c.3.1 above. Chapter 8 describes the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO_2 cost adder levels were used to inform the cost/risk tradeoff analysis. The preferred portfolio was also shown to meet reliability goals on the basis of average annual Energy Not Served and other reliability measures (Chapter 7).
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp evaluated several types of distribution generation, including combined heat and power and customer-owned standby generation. The results of these evaluations are documented in Chapter 8.
Guideline 13: Resource Acquisition		

No.	Requirement	How the Guideline is Addressed in the 2007 IRP
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party 3. Identify any Benchmark Resources it plans to consider in competitive bidding	Chapter 8 outlines the procurement approach for each proxy resource type identified in the action plan. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 8. Benchmark resources for the 2012 are cited in Chapter 3, Recent Resource Procurement Activities.
13.b	For gas utilities only	Not applicable

Table I.4 – Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Utah Public Service Commission responsibility
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the IRP process.
3	Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings.	Not addressed; ratemaking occurs outside of the IRP process
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix F.
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analy-	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Chapter

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
	sis.	6 for a description of the methodology employed.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	Supply, transmission, and demand-side resources were evaluated on a comparable basis using PacifiCorp's capacity expansion optimization model (CEM). (The one exception was Class 2 DSM, due to the unavailability of supply curves for this IRP.) Also see the response to number 4.b.ii below.
7	Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan.	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.
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions, and meets all formal state IRP guidelines.
9	The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	PacifiCorp's business plan is directly related to the IRP; the business planning process is informed by the IRP resource analysis, the action plan, and subsequent procurement activities. Due to timing and scope differences, these two plans do not match in all respects. The 2007 IRP will be used to inform the next version of the Business Plan.
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk	Chapter 2 discusses the planning principles used for developing this IRP, and the qualifications surrounding the company's long term resource planning process. The company notes that this definition does not specify what constitutes "optimality" given resource decision-making constrained by (1) consideration of risk, uncertainty, disparate state policy goals and stakeholder interests, and (2) the complexity and limitations of the IRP modeling effort. As indicated in Chapter

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
	and uncertainty.	2, PacifiCorp believes that a successful IRP attempts to derive a robust resource plan under a reasonably wide range of potential futures
2	The Company will submit its Integrated Resource Plan biennially.	For this IRP, the company received a filing extension from the Utah Public Service Commission and other state commissions. This extension was necessary to realign the IRP process to address new and expected changes in state resource policy that came into play well into this IRP development cycle.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix F.
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both deterministic scenario analysis as well as for stochastic short-term and long-term variability. Details concerning the load forecasts used in the 2007 IRP are provided in Chapter 4 and Appendix A. Details on the forecast ranges developed for scenario and stochastic analysis are documented in Chapter 6 and Appendix E, respectively.
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	Price risk associated with market sales is captured in the company's stochastic simulation results. Current off-system sales agreements are included in the IRP models. The company is not planning to enter into additional long term firm sales agreements; therefore, associated risks do not impact the selection of the preferred portfolio. For system balancing sales, PacifiCorp recognizes that transactions may be affected by new resource constraints imposed by regulators (carbon emission and renewable portfolio standards in particular). These impacts will

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
		be considered in future IRP resource analyses.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Appendix A documents how demographic and price factors are used in the load forecasting process. Appendix A also documents price elasticity studies conducted on Utah load.
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the Capacity Expansion Module. There were some exceptions due to the availability of data for this IRP, such as Class 2 DSM. Chapter 6 provides a discussion on how Class 2 DSM resource potential was addressed in this IRP.
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp contracted with Quantec, LLC to assess the technical, market, and achievable potential for various dispatchable and price-responsive load control programs (PacifiCorp Class1 and Class 3 DSM). The associated assessment is described in Chapter 5, while Quantec's assessment report is included as Appendix B. PacifiCorp's treatment of conservation programs (Class 2 DSM) is addressed in Chapter 6 ("Public Utility Commission Guidelines for Conservation Program Analysis in the IRP").
4.b.ii	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, and transmission. Chapters 5 and 6 document how PacifiCorp developed and assessed these technologies. In brief, the company used a combination of PacifiCorp generation staff expertise, Electric Power Research Institute Technical Assessment Guide (TAG®) data, and capacity expansion optimization modeling to assess these technologies. Generation resource types were initially assessed by PacifiCorp's

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
		generation experts, and a list that captures the salient technology types and configurations was assembled (Chapter 5, Tables 5.1 and 5.2). Decisions on what generation resources to include in the Capacity Expansion Module was based on generation staff recommendations and the need to limit resource options to a manageable number based on model constraints and run-time considerations. (The company notes that the need to place restrictions on the number of resource options is a common IRP problem for utilities that use such optimization models for long-term planning.) Based on the modeling lessons learned for this IRP and the anticipated expansion of resource options arising from the DSM potentials study due in June 2007, PacifiCorp intends to explore new resource screening methods to accommodate a broader range of technologies while meeting the requirement to assess technologies on a 'consistent and comparable basis."
4.b.iii	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.	PacifiCorp captures and models these resource attributes in its IRP models. The proxy demand curves used to represent demand-side management programs explicitly incorporates estimated rates of program and event participation.
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Chapter 8 ("IRP Resource Procurement Strategy").
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2007-2026)
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe spe-	The action plan is provided in Chapter 8. A status report of the actions outlined in the previous action plan (2004 IRP and the 2004 IRP Update) is provided as Appendix G.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
	cific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	
4.f	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.	Chapter 8 includes a section that describes PacifiCorp's strategy for meeting this requirement. In short, the company will use its IRP models, in conjunction with scenario analysis, to evaluate resource bids submitted under its Base Load Request For Proposals, issued on April 5, 2007.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Chapter 5 (Tables 5.2 through 5.4). The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Portfolios were evaluated using CO_2 adders that ranged from $0 to $61 per ton. ● The cost impact of renewable portfolio standards is captured in several portfolio scenario analyses (Chapter 7) ● PacifiCorp conducted a study to determine the cost and risk impact of widespread adoption of a greenhouse gas emissions performance standard (Chapter 7) ● Appendix B includes a section on DSM program valuation, which covers societal value factors (for example, environmental and reliability benefits)
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should	Discussions on market risks by resource type are included in Chapter 5 ("Resource Descriptions"). Resource capital cost uncertainty and technological risk is addressed in Chapter 5 ("Handling of Technology Improvement

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
	bear such risk, the ratepayer or the stockholder.	Trends and Cost Uncertainty”). For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Chapter 2.
4.i	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	PacifiCorp discusses how planning flexibility came into play for the selection of the preferred portfolio (Chapter 7, “Preferred Portfolio Selection and Justification”).
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk. This trade-off analysis is documented in Chapter 7. A discussion on the trade-off between cost and the planning reserve margin is also provided in Chapter 7 (“Planning Reserve Margin Selection”)
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.	PacifiCorp estimated environmental externality costs for CO_2, NO_X, SO_2, and mercury with use of cost adders and assumptions regarding the form of compliance strategy (for example, cap-and-trade versus a per-ton tax for CO_2). For CO_2 externality costs, the company used scenarios with various cost adder levels to capture a reasonable range of cost impacts.
4.l	A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	This narrative is provided in Chapter 4 (“Existing DSM Program Status”).
5	PacifiCorp will submit its IRP for public comment, review and acknowledgement.	PacifiCorp distributed the draft IRP document for public review and comment on April 20, 2007. This IRP report constitutes

No.	Requirement	How the Standards and Guidelines are Addressed in the 2007 IRP
		the formal submission of the IRP for acknowledgement.
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required.	Not addressed; this is a post-filing activity.
7	Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

APPENDIX J – WIND RESOURCE METHODOLOGY

This appendix summarizes the wind resource analyses used to help characterize wind resources included in PacifiCorp's IRP models. Specifically, the appendix covers (1) the expected cost of integrating various amounts of wind generation with other portfolio resources—reflecting a refinement and update of previous analysis conducted for PacifiCorp's integrated resource planning, (2) a resource screening effort to determine a base amount of wind resources to include in portfolios subjected to stochastic production cost simulation, and (3) the calculation of capacity planning contribution of wind resources, accounting for generation variability.

In addition to summarizing the results of its wind resource studies, this appendix briefly describes current efforts by organizations in the Pacific Northwest to assess wind integration implications. Finally, the last section of this appendix discusses the role of resource fuel type on the company's strategy for integrating wind resources. This discussion addresses an Oregon Public Utility Commission requirement to investigate this topic for the 2007 IRP.

A new methodology was developed to explicitly calculate the load following reserve requirement based on the uncertainty in load for the next hour on an operational basis, which allowed PacifiCorp to apply the same analytical approach to estimating the incremental reserve requirements for wind. The availability of hourly wind data for resources distributed across PacifiCorp service territories over comparable historical time horizons enabled analysts to include proxy wind resources with realistic operating characteristics into the analysis. Further, a development in techniques for estimating load carrying capability allowed analysts to estimate the capacity contributions of various wind combinations of wind developments that restricted interactions due to correlated generation from nearby plants. Analysts were able to improve the characterization of wind operations and interactions with the power system in the present analysis.

WIND INTEGRATION COSTS

Across all analyses, wind integration costs have generally been divided into two categories – incremental reserve requirements and system balancing costs. The former is related to the need for dynamic resources to be held in reserve, able to respond on a roughly ten minute basis to rapidly changing load/resource balance conditions. Since wind resource generation can be quite variable over time periods from about ten minutes to several hours, it will be necessary to increase the amount of reserves as the quantity of wind resources on the system increases. System balancing costs represent the difference in value between the energy delivered from wind resources compared to that delivered from less volatile resources. Consistent with previous studies, PacifiCorp reviewed both categories of wind integration costs: the incremental reserve requirement and the system balancing cost.

Incremental Reserve Requirements

Operating reserves are divided into categories based on purpose and on characteristics. Naming conventions for categorizing reserves by their intended purpose are not standard in the industry. Reserves held for responding to the sudden failure of generation or transmission equipment are usually called "contingency reserves". Reserves held to respond to changes in system frequency over a period of a few seconds will be referred to as “regulating reserves”. Generation that can be brought on over a multiple-minute time period will be termed “load following reserves.”

Wind projects are not expected to affect the need to hold contingency reserves, as there is no significant difference between wind generation and other types of generation with respect to sudden equipment failures, or other outages. The multiplicity of individual generators within a typical wind farm inherently makes them less susceptible to losing the entire output of the farm due to generator or turbine failures (but not transmission-related outages). Wind projects are subject to relatively rapid shutdown when wind speeds reach the cutout level. However, this has not been a significant problem in practice, as individual wind turbines do not tend to shut down simultaneously.

Similarly, regulating reserve requirements do not appear to be significantly affected by wind turbines[4]. The second-by-second variations in wind project output are found to be not significantly different from other generating units and the ambient fluctuations of the load. They are also not correlated with either load fluctuations, or distant wind projects.

Wind variations over periods of ten minutes to an hour are significant, and can cause operators to rapidly start up units on short notice within an hour. Fluctuations of the combined output of a collection of wind projects increases with the amount of total wind generation connected to the system.

For the 2007 IRP, a new methodology was developed to explicitly calculate the load following reserve requirement based on the uncertainty in load for the next hour on an operational basis. Operators have estimates of the behavior of loads for the next hour and move to bring on or back off resources as necessary to accommodate the expected change. Knowing that the actual load of the next hour will likely be different than the forecast and that there will be deviations within the hour, operators hold additional resources ready to respond should they underestimate the need for resources. (Generally, overestimates are not a problem, though it is an additional concern). Reserve levels are established to ensure that the shortfall can be met a minimum percentage of the time—generally around 95 percent. The methodology is graphically illustrated in Figure J.1, which shows how the load forecast changes from one hour to the next. Assuming that the range of actual outcomes for the next hour can be approximated by a normal distribution, the amount of additional reserve capability that is necessary to provide assurance of having adequate resources available at least 95 percent of the time can be calculated.

This methodology can be applied first to the system load alone and then again to the system load net of wind generation. The difference between the two results is the estimated incremental reserve requirement due to the wind resources.

[4] DeMeo, Grant, Milligan, and Schuerger, “Wind Plant Integration: Costs, Status, and Issues”, IEEE Power & Energy Magazine, Vol 3 Number 6, Nov/Dec 2005, p. 41.

Figure J.1 – Load Following Reserve Requirement Illustration

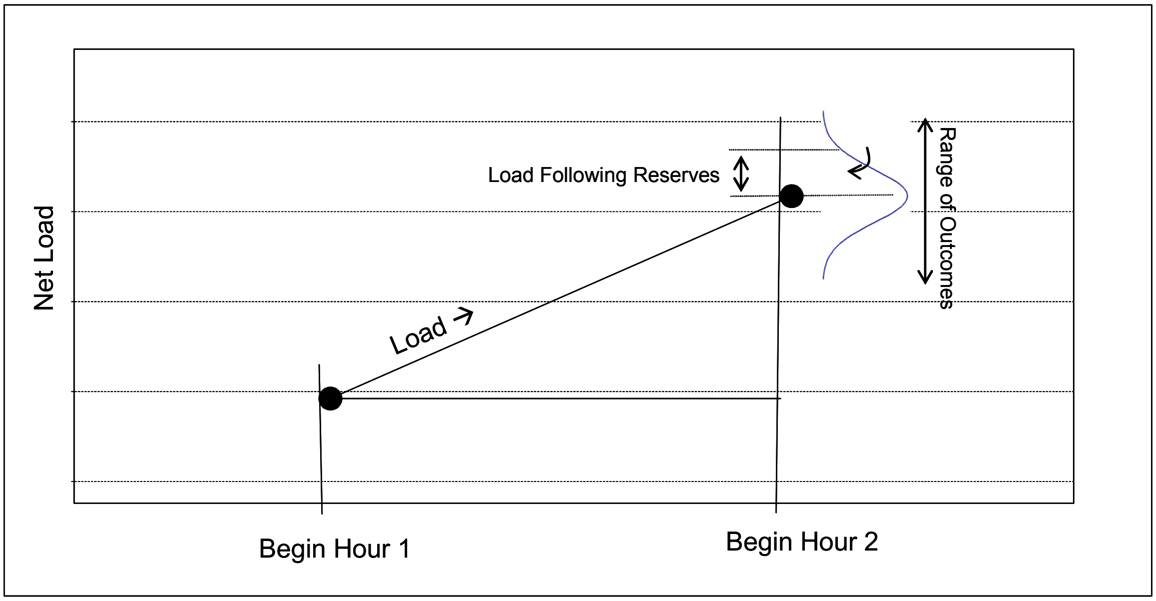
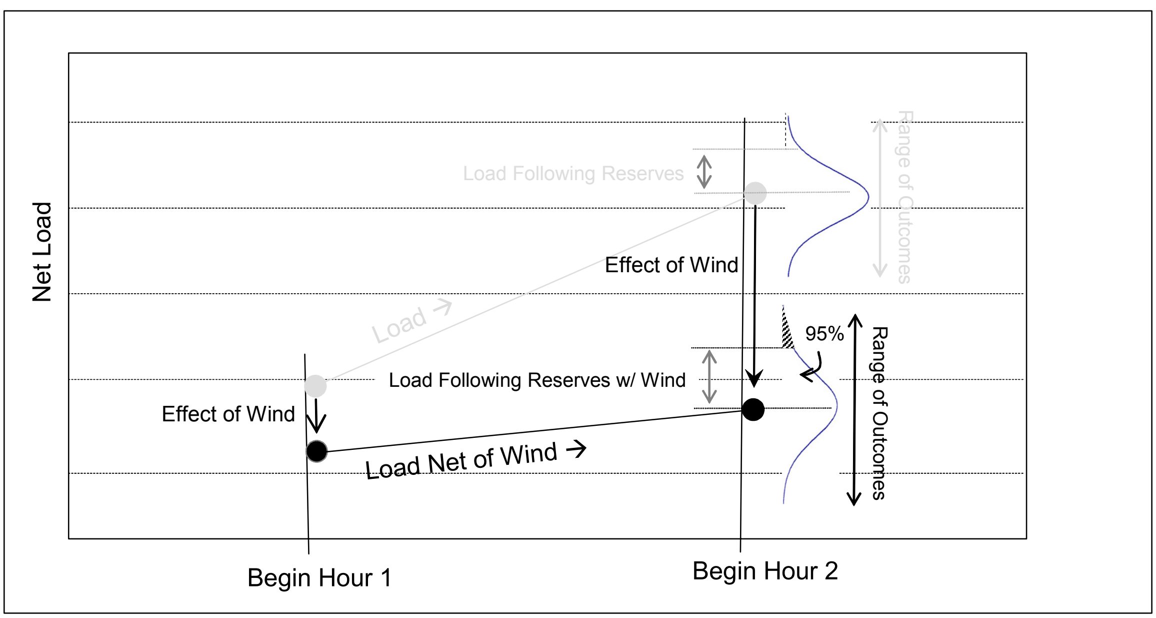


Figure J.2 shows the variability of the load forecast and the variability of the wind energy rolled together by performing the same analysis on the forecast of load net of wind energy. The expected value of load net of wind will be less than or equal to the load forecast for any given hour. However, the variability of load net of wind is greater than that of load alone. It is the difference of between the variability of load and the variability of load net of wind for a given hour that described the incremental reserves that should be attributed to wind resources.

Figure J.2 – Load Following Reserve Requirement for Load Net of Wind

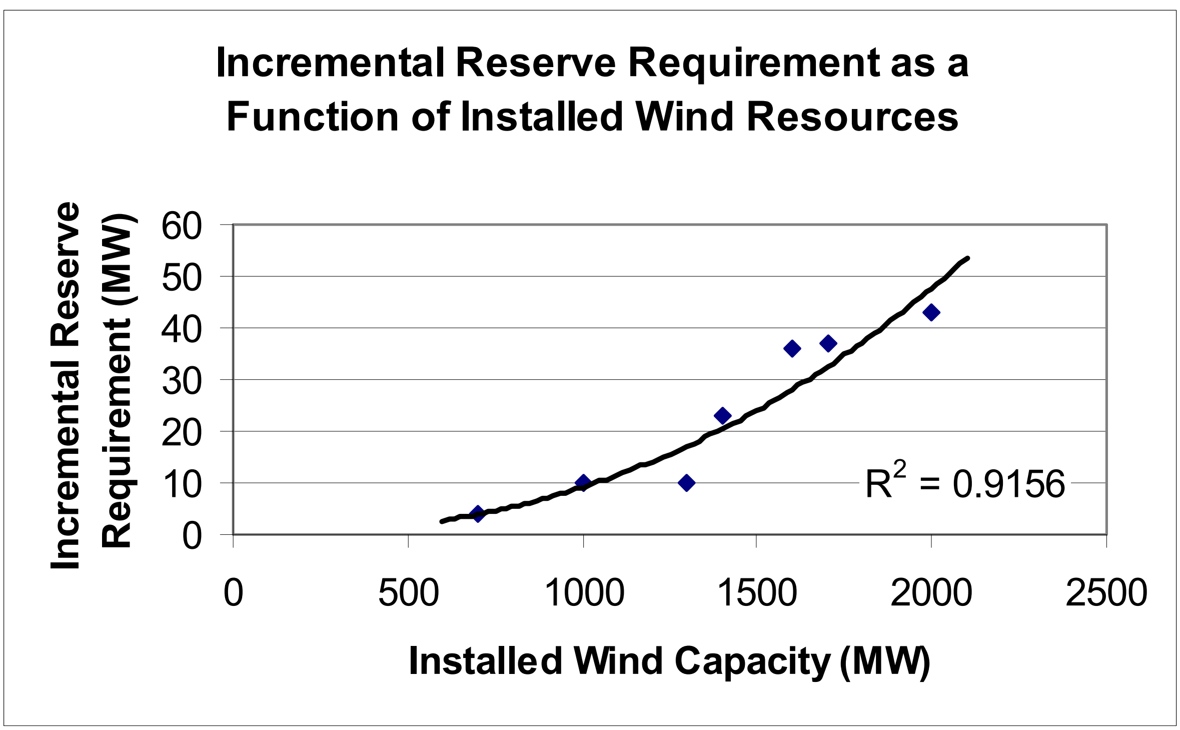


Early in the 2007 IRP process, the result of applying this methodology to the PacifiCorp system with an additional 1,400 megawatts of wind resources was an estimated 30 megawatts of additional reserve requirements. That amount of spinning reserve was added to the stochastic PaR model runs to simulate the additional cost.

In follow up analyses of the preferred portfolio, the company confirmed that using even the simplest forecast techniques greatly reduced the forecast error of both load and wind and consequently reduced the anticipated need for load following reserves. Figure J.3 displays the estimated incremental load following requirement calculated using PacifiCorp's updated load forecast and varying the level of wind resources following the build pattern of the preferred portfolio. For the 1,400 megawatt level of wind installation, the estimated need for incremental reserves is approximately 22 megawatts. For the preferred portfolio with 2,000 megawatts of wind resources, Figure J.4 shows an estimated need for 43 megawatts of additional load following reserves due to wind resources.

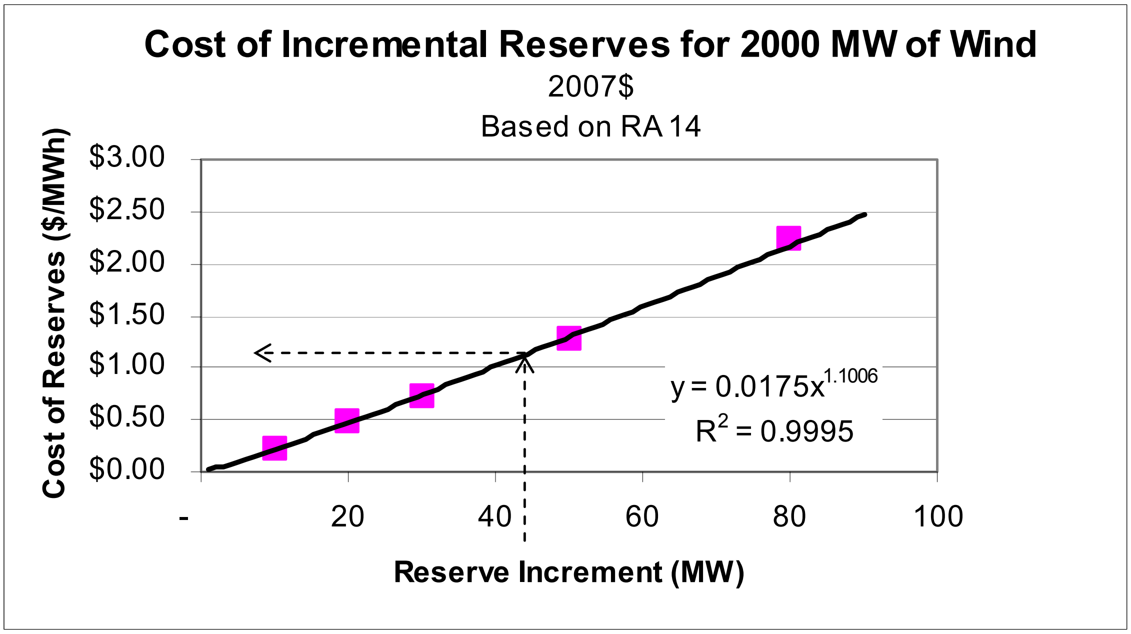
This analysis represents a reduction in the estimate of needed reserves compared with previous estimates. The major difference from prior studies is the development of a systematic method for estimating load following reserve requirements. The 2003 IRP study was based on the hourly variability of wind resources, whereas the current analysis is based on the hourly uncertainty in generation. It is further benefited by the more extensive operating data available since the 2003 study.

Figure J.3 – Incremental Reserve Cost Associated with Various Wind Capacity Amounts



By running the PaR model studies with and without the incremental load following reserves, the company can estimate the cost of the incremental reserves at varying levels. This can be converted to a unit cost by dividing the cost by the total amount of wind energy. Figure J.4 shows the results of those studies.

Figure J.4 – Operating Cost of Incremental Load Following Reserves



From Figure J.4, the unit cost of 43 megawatts of incremental reserves attributed to the 2,000 megawatts of wind capacity in the preferred portfolio is estimated to be $1.10 per megawatt hour of wind energy.

System Balancing Costs

System balancing costs represent the additional operating costs incurred as a result of adding wind generation to PacifiCorp's system. For the 2003 IRP, the system balancing costs associated with wind resources were evaluated by comparing one model run with wind resources specified with an hourly energy pattern to another run where the hourly wind energy was replaced by an equal amount of energy expressed as a flat annual shape. This methodology was repeated for the 2007 IRP preferred portfolio with the following modifications.

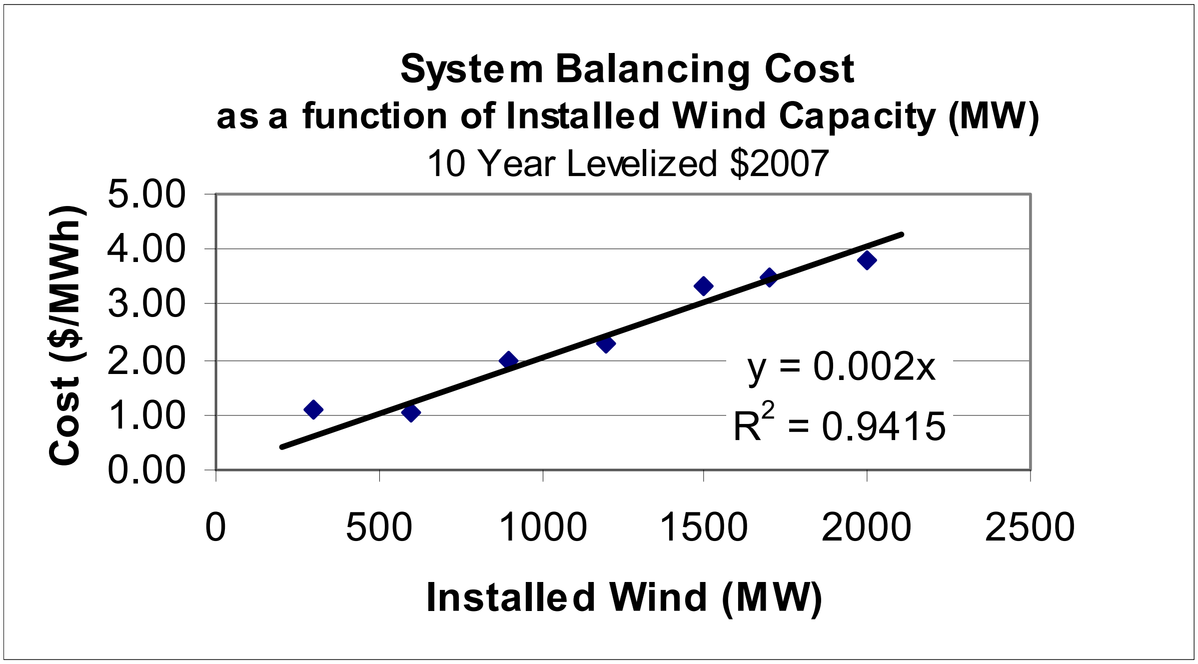
- First, the hourly wind patterns for the base study were substantially upgraded. Data from multiple Pacific Northwest sources, including PacifiCorp's actual wind energy, was modified for project size and mapped to the proxy wind resources by location. In the case of multiple "plants," some of the data was shifted by an hour or two to represent diversity within a wind area. The Wyoming projects were updated to a 40 percent capacity factor to be consistent with actual information coming from that area.

- The comparison to the annual block size was repeated for several sized accumulations of wind projects across PacifiCorp's system using the wind data and build patterns consistent with the preferred portfolio analysis.

Using the equivalent annual block against the hourly wind patterns confirmed earlier findings that as wind resources accumulate the system balancing costs also increase on a unit cost basis.

The 2007 IRP results are shown in Figure J.5. The results are similar to previous studies.

Figure J.5 – PacifiCorp System Balancing Cost



From Figure J.5 it can be seen that 2000 megawatts of wind capacity installed on PacifiCorp's system brings with it approximately $4.00 per megawatt-hour less than an equivalent amount of energy shaped as an annual base load resource

While some of the regional studies employed smaller sized energy blocks for similar comparisons, PacifiCorp continues to use the annual block-size approach. Equivalent energy generated at a constant rate for the entire year and priced at market is the competing resource that PacifiCorp uses in its resource economic evaluations.

<u>Use of Wind Integration Cost Estimates in the 2007 IRP Portfolio Analysis</u>

Wind integration costs for the purposes of the CEM runs were based on 2004 IRP results due to the timing of the needed analyses. In the PaR model, the system balancing costs are implicit as the wind resources are represented as hourly generation patterns from the quasi-historical data. The incremental load-following reserve requirement, calculated outside of the main IRP models, was added as a constraint in the stochastic PaR runs for the candidate and preferred portfolios in the 2007 IRP. (CEM does not model reserve requirements, and so was not affected by the analysis).

Because the hourly generation patterns of wind and the increased incremental reserves are modeled explicitly in the PaR model the PVRR includes both types of cost. The integration cost for the 2,000 megawatts of wind resources included in the preferred portfolio is estimated to be $5.10 per megawatt hour of wind energy.

PacifiCorp is continuing to explore methodologies to confirm and quantify wind variability with respect to the need for operating reserves. In particular, sub-hourly data is being captured to test the impact of deviations within the hour. Continued study of the impacts of integrating large quantities of wind in PacifiCorp's system is identified in the IRP action plan (See Chapter 8).

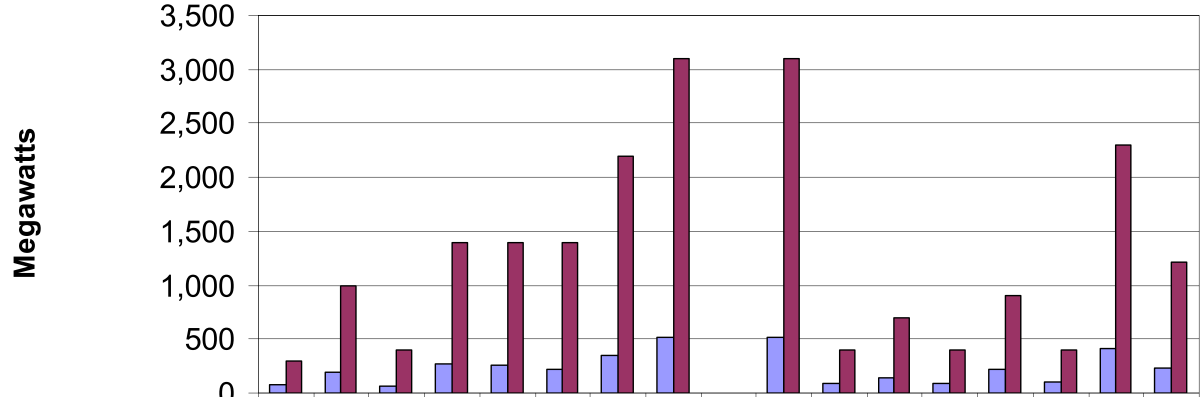
DETERMINATION OF COST-EFFECTIVE WIND RESOURCES

PacifiCorp used the CEM to help determine the quantity of wind considered reasonable given a range of alternative assumptions concerning future portfolio costs. The explicit costs of wind (capital and integration costs, less production tax credits and the value of renewable energy credits) were entered into the CEM. The results of the alternative future scenario CEM runs were examined to find a rough cost-effectiveness order for the proxy wind resource sites. Nearly all of the CEM runs found wind to be part of a cost-effective resource portfolio.

Fixed in each of the runs were the 400 megawatt MEHC acquisition commitments made to state commissions. In the "medium case" alternative future scenario (Alternative Future #11), the CEM added 700 nameplate megawatts of wind resources to the system, for a total of 1,100 megawatts of additional renewable resources by 2016.

Figure J.6 shows the cost-effective wind capacity amounts (both nameplate and capacity contribution) selected by the CEM for each of the 16 alternative future scenarios. The average for all the alternative future runs was over 1,200 megawatts (235 megawatt capacity contribution), or 1,600 megawatts including the 400 megawatt base assumption quantity. These results are consistent with the 1,400 megawatt determination for the level of cost-effective renewables reported in PacifiCorp's 2004 IRP.

Figure J.6 – Renewables Capacity Additions for Alternative Future Scenarios



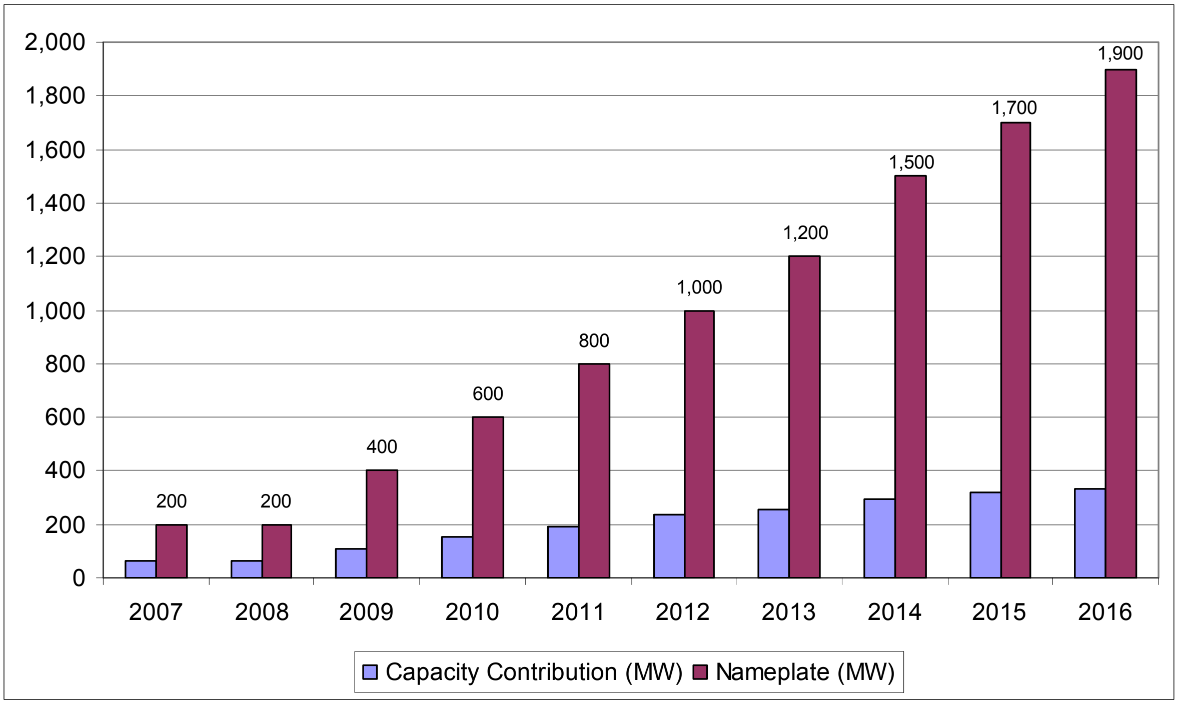
	CAF00	CAF01	CAF02	CAF03	CAF04	CAF05	CAF06	CAF07	CAF08	CAF09	CAF10	CAF11	CAF12	CAF13	CAF14	CAF15	Ave.
Wind Capacity Contribution	82	196	60	277	259	215	354	514	0	514	85	148	95	222	99	410	235
Renew ables Nameplate	300	1,000	400	1,400	1,400	1,400	2,200	3,100	-	3,100	400	700	400	900	400	2,300	1213

A CEM sensitivity run was performed to test the quantity of wind selected given the expiration of renewable production tax credits, but with otherwise favorable scenario conditions for wind development. These favorable conditions included a high CO_2 adder ($25/ton in 1990 dollars), high natural gas and electricity prices, and a high system-wide renewable sales percentage requirement attributable to renewable portfolio standards. See Chapter 6, Modeling and Risk Analysis Approach, for more details on scenario assumptions.

In this sensitivity, the CEM selected 1,900 megawatts of wind by 2016 (capacity contribution of 335 megawatts). Figure J.7 shows the cumulative annual resource addition pattern for 2008 through 2016. The sensitivity results indicate that given the assumed favorable scenario conditions, the expiration of the production tax credits results in 1,200 megawatts less wind capacity selected for the optimal portfolio.

Based on these results, PacifiCorp identified 1,000 to 1,600 megawatts of additional nameplate wind capacity for specifying proxy renewable resources to be included in portfolios subjected to stochastic production cost simulation.

Figure J.7 – Cumulative Capacity Contribution of Renewable Additions for the PTC Sensitivity Study



WIND CAPACITY PLANNING CONTRIBUTION

For planning purposes, most resources are assumed to contribute their nominal (or "nameplate") capacity to meeting the planning reserve margin level. It is recognized that wind resources cannot be depended on to contribute their full nameplate capacity to meeting planning reserve margin, since the probability of achieving that level on a peak hour is relatively low, and virtually zero for a large portfolio of diverse wind resources. Nevertheless, it was recognized that some level of capacity contribution attributed to wind projects is appropriate, and PacifiCorp has adopted the effective load carrying capability of wind projects as the standard. In short, the effective load carrying capability of a resource is the amount of incremental load the system can meet with the incremental resource without degrading the reliability of meeting load.

PacifiCorp used the stochastic PaR model to estimate the monthly load carrying capability of a wind resource using an analytical method based on the Z statistic.[5] The analytical method of estimating load carrying capability was necessary in order to compute the capacity contributions from a large number of wind projects and different combinations of projects. The result of this analysis as applied to the proxy (100-megawatt) wind resources is shown in Table J.1 below. Key observations from these results include the following.

[5] See, Dragoon, K., Dvortsov, V, "Z-method for power system resource adequacy applications" IEEE Transactions on Power Systems (Volume 21, Issue 2, May 2006), pp. 982 – 988.

- The incremental capacity contribution within an area declines due to correlations (lack of diversity) among wind projects in an area.
- The capacity contribution decline is greatest for projects with more variability of their on-peak contributions.
- The capacity contribution varies over the year, primarily due to expected on-peak generation.

Table J.1 – Incremental Capacity Contributions from Proxy Wind Resources

Regional Resource	Additions (MW)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NC OR	-100	1	18	28	17	25	35	37	27	22	14	5	5
	-200	0	8	16	7	14	24	28	18	12	5	0	0
	-300	0	0	3	0	3	14	19	10	2	0	0	0
	-400	0	0	0	0	0	3	10	1	0	0	0	0
SE WA	-100	19	14	33	13	13	10	12	7	10	14	16	16
	-200	8	2	20	2	1	0	2	0	0	3	5	4
	-300	0	0	8	0	0	0	0	0	0	0	0	0
	-400	0	0	0	0	0	0	0	0	0	0	0	0
EC NV	-100	18	20	32	32	23	28	27	23	21	23	19	28
	-200	15	17	29	26	20	24	23	20	17	20	17	24
	-300	13	14	25	20	16	20	20	18	13	16	14	21
	-400	10	12	21	14	13	17	16	15	9	13	12	17
SE ID	-100	26	37	59	35	31	32	25	32	22	32	38	32
	-200	20	31	53	29	26	27	21	28	17	26	32	26
	-300	14	24	47	24	22	22	17	24	13	21	25	20
	-400	8	17	41	18	17	17	13	20	8	16	18	14
WC UT	-100	13	10	25	31	35	27	20	26	26	24	20	19
	-200	10	9	21	27	31	24	18	22	22	20	17	16
	-300	7	7	17	22	26	20	15	18	18	16	14	13
	-400	4	6	13	17	21	17	12	15	13	13	11	10
SW WY	-100	33	27	36	33	30	30	23	24	25	31	24	34
	-200	27	24	29	27	26	25	20	21	22	26	21	28
	-300	21	20	22	21	21	21	18	18	19	21	18	22
	-400	16	16	15	16	16	16	15	16	16	16	15	16
	-500	10	12	8	10	11	11	13	13	13	11	13	10
	-600	5	8	1	4	6	7	10	10	9	6	10	4
	-700	0	5	0	0	2	2	7	7	6	1	7	0
SC MT	-100	42	34	35	24	26	26	27	26	28	32	42	33
	-200	34	27	26	19	23	21	24	23	24	28	33	26
	-300	26	20	18	14	19	16	21	20	21	23	25	18
	-400	18	14	10	9	15	11	18	18	18	19	17	11
SE WY	-100	35	26	30	25	22	19	13	15	18	23	44	37
	-200	30	21	24	21	18	16	11	13	15	18	43	32
	-300	25	16	19	17	14	12	9	10	11	13	43	27
	-400	20	12	13	13	10	9	7	8	7	9	42	23
	-500	15	7	7	9	6	6	5	6	3	4	41	18
	-600	9	2	2	5	2	3	3	3	0	0	40	13
	-700	4	0	0	1	0	0	1	1	0	0	39	8

REGIONAL STUDIES

Utilities are studying wind resources in order to quantify the full cost of integrating wind energy into existing systems. In March 2007, Northwest Power and Conservation Council released the Northwest Wind Integration Action Plan (the Action Plan). A joint product of the region's utility, regulatory, consumer and environmental organizations, the Action Plan addresses several major questions surrounding the growth of wind energy and suggests areas that need further consideration.

The Action Plan summarizes the results of wind integration cost studies performed by PacifiCorp (in its 2004 IRP), Avista, Idaho Power, Puget Sound Energy, and Bonneville Power. The report lists the key findings of these northwest studies. All of the studies find that the cost of integrating wind starts low as the variability of small quantities of wind generation is lost in the volatility of the system load, and grows as the amount of wind resource increases. Collectively the studies list the size of the control area in relation to the amount of wind, the geographic diversity of the wind locations, the amount of flexibility of the receiving utility, and the access to robust markets as key factors affecting the cost of integrating wind energy.

Table J.2 reproduces the data from the report. The Action Plan includes a summary of each of the study methodologies in its appendix B. PacifiCorp's estimate of wind integration costs ranked among the lowest of the wind integration costs. Only Bonneville Power ranked lower. PacifiCorp's low integration cost is likely the result of the opportunity to maximize the use of each of the key factors: a large system, wide geographic coverage allowing for dispersed wind sites, and a flexible system with multiple points of access to the energy markets.

Table J.2 – Wind Integration Costs from Northwest Utility Studies [6]

Utility	Peak Load (MW)	Wind Penetration ($/MWh of Wind Generation)			
		5%	10%	20%	30%
Avista	2,200	$ 2.75	$ 6.99	$ 6.65	$ 8.84
Idaho Power	3,100		$ 9.75	$11.72	$16.16
Puget Sound Energy	4,650	$ 3.73	$ 4.06		
PacifiCorp (2003-2004 IRP)	9,400	$ 1.86	$ 3.19	$ 5.94	
BPA (within-hour impacts only)	9,090	$ 1.90	$ 2.40	$ 3.70	$ 4.60

In the wake of the regional load peak of July 24, 2006, when wind turbines made only a small contribution to generating capacity at the time of the peak, the wind resource contribution to peak capacity is being reassessed by Northwest Resource Adequacy Forum (NWRA Forum) as Action #1 of the Action Plan.[7]

[6] Source: NWRA Forum, Northwest Wind Integration Action Plan, (March 2007 pre-publication version), page 31.
[7] NWRA Forum, Northwest Wind Integration Action Plan (March 2007, pre-publication version). See Action 1, p.48,

EFFECT OF RESOURCE ADDITION FUEL TYPE ON THE COMPANY'S COST TO INTEGRATE WIND RESOURCES

As the company installs larger volumes of wind resource generation, the cost to integrate these intermittent resources is anticipated to increase. This is because more non-wind resources must be held back to allow flexibility to follow the intra-hour volatility of the wind generation. Resources with greatest the dispatch flexibility that are not already in use to serve load are typically used for integration.

The hour to hour dispatch of non-wind resources is not a trivial decision. The company's owned hydro plants with storage capability and the Mid-Columbia hydro contracts, all of which have the highest flexibility, can often provide the needed flexibility. However, these hydro resources do not have enough volume to integrate all of the anticipated wind variability. Partially loaded gas turbines can provide additional flexibility. Due to its low cost, coal is normally fully utilized to serve load rather than backed off to provide wind integration.

It is flexible resources that are operating on the margin that influence the cost of wind integration. When evaluating the effect of the fuel type of resource additions on PacifiCorp's cost to integrate wind resources, it is most likely that the IRP natural gas-fired additions will have the most effect on integration costs.

Final Report

Demand Response Proxy Supply Curves

Prepared for:
PacifiCorp

September 8, 2006

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Table of Contents

I. Introduction

This report summarizes the results of an assessment of technical, market, and achievable potentials for demand response (DR) resources for PacifiCorp's system overall and its two control areas: West (California, Oregon, Washington), and East (Idaho, Utah, Wyoming). The results of this assessment form the basis for producing proxy supply curves for Class I and Class III demand-side management (DSM) resources, which will be incorporated into PacifiCorp's 2006 integrated resource plan (IRP).

The project's key objectives included: meeting PacifiCorp's IRP regulatory requirements; addressing public comments regarding comparable treatment of DR resources, with respect to power production options in PacifiCorp's resource portfolio evaluation; and assisting the company in further refining DR opportunities. Specifically, the project is intended to address an Oregon Public Utility Commission (OPUC) 2004 IRP requirement to evaluate Class I and Class III DSM resources, using a supply curve approach for portfolio modeling in PacifiCorp's 2006 IRP. In 2007, PacifiCorp plans to complete a more detailed assessment of DSM potentials, providing state-specific results. Therefore, this project is to be considered preliminary, and to serve as a "proxy" for the DR portion of that study.

The resulting supply curves show the price/quantity relationship for various categories of DR strategies and options within Class I and Class III DSM resources, as defined by PacifiCorp. As part of this project, to facilitate the economic screening of alternative DR options, research was also conducted regarding current utility practices in valuation of DR resources, with an emphasis on identifying key value drivers used in this evaluation.

This report is organized in five parts. The remainder of this chapter provides a general overview of DR resources, as well as the specific program concepts used in this study. Section II describes the results of research on DR value factors and valuation methods. Section III reports the results of the DR potential assessment. Section IV describes the general approach and methodology for estimating resource potentials. Detailed data and assumptions used to derive resource potentials for each specific DR resource are described in Section V.

Demand-Response Resources

Demand-response resources are comprised of flexible, price-responsive customer loads that may be curtailed in whole or in part during system peak load periods, when wholesale market prices exceed the utility's marginal power supply cost, or in the event of a system emergency. Acquisition of DR resources may be based on either reliability considerations or economic/market objectives. Demand response objectives may be met through a broad range of price-based (e.g., time-varying rates and curtailable rates) or incentive-based (e.g., direct load control) strategies. For the purpose of this project, DR is defined based on PacifiCorp's characterization in terms of two distinct classes of firm and non-firm resource options:

Class I (Firm) DSM Resources

This class of DR strategies allows either direct or scheduled interruption of electrical equipment and appliances such as water heaters, space heaters, central air-conditioners, commercial energy management systems, and irrigation pumps. Programmatic options in this class of resources fall into the four following categories:

- Fully dispatchable programs, 10 minute or less response, up to 87 hours annually (e.g., direct curtailment of residential air conditioning, water heating, space heating)
- Fully dispatchable programs, over 10 minute response, up to 87 hours annually (e.g., commercial energy management system coordination)
- Scheduled firm up to 170 hours annually (e.g., irrigation load curtailment)
- Scheduled firm at 360 or more hours annually (e.g., thermal energy storage)

Pre-determined incentive payments are typically the main instrument for compensating participants in this class of programs.

Class III (Non-Firm) DSM Resources

Demand response resources in this class differ from those in Class I in that their dispatch is outside the utility's control and, therefore, less reliable or "firm." Resources in this class include curtailable rate programs, time-varying prices (time-of use, real-time pricing, critical peak pricing), and demand buyback or demand bidding programs. Incentives are provided to participants either as a special tariff (curtailable rates, time-varying prices) or per-event payments (demand buyback).

Although residential seasonal programs such as Customer Energy Challenge are considered Class III resources, they are not included in this analysis. Arguably, such programs serve better as contingency resources during periods when energy prices are projected to be high and expected to stay high for an extended period of time, rather than as capacity relief resources.

Program Concepts

Before developing resource potential estimates, it is important to consider how each resource is likely to be structured as a demand response product or program. Using the definitions of Class I and Class III resources above, program concepts were developed as a framework for estimating market potential. For the purpose of this assessment, five specific program concepts were formulated, as described below.

Fully Dispatchable

Often referred to as direct load control (DLC), these fully-dispatchable programs are designed to reduce the demand during peak periods by turning off equipment or limiting the "cycle" time (i.e., frequency and duration of periods when the equipment is in operation) during system peak. The offerings for the residential sector are seasonally divided, while the potential with large commercial and industrial customers typically focus on summer cooling loads only. Three program concepts in this category of resources were included in the analysis:

- **Winter.** Direct load control of water and space heating during winter are the program options considered in this class. This program would be dispatched during the morning and evening peak hours. The largest potential for such a program will be in the West control area because of the higher saturation of electric space heating. Incentives are generally paid on a monthly basis. Although there are no large scale DLC programs in the Northwest, Portland General Electric (PGE) and Puget Sound Energy (PSE) have both studied implementation through pilot programs. Nationally, there are many utilities with space and/or water heating controls, including Duke Power, Wisconsin Power and Light, Great River Energy, and Alliant Energy.
- **Summer.** The main DR product in this group is direct load control of air-conditioning units[1], which are typically dispatched during the hottest summer days, and are common place due to the relatively high summer loads in warm climates. PacifiCorp currently pays monthly incentives to residential and small commercial participants in Utah's Cool Keeper AC Load Control program. There is approximately 130 MW of connected load for this program. Using a 50% cycling dispatch strategy, approximately half can be expected during an event. In addition to those utilities listed above, Nevada Power, Florida Power and Light, Alliant Energy, and the major investor-owned-utilities in California run air conditioner direct load control programs (e.g., Sacramento Municipal Utility District and San Diego Gas and Electric).
- **Large Commercial & Industrial.** Direct control of large commercial and industrial (C&I) customers requires coordination with the existing energy management systems (EMS). The focus of this program is adjustment of the heating, ventilation, and air conditioning (HVAC) equipment during the top summer hours. Incentives are generally paid on a per-kW or per-ton (of cooling equipment) basis. Some utilities running comparable programs include Florida Light & Power, Hawaiian Electric, and Southern California Edison.

Scheduled Firm

Program strategies that provide consistent reductions during pre-specified hours target customers with usage patterns and technology that allow scheduled shifting of consumption from peak to off-peak periods.

- **Irrigation Pumping.** Irrigation load control is a candidate for summer DR due to the relatively low load factor (approximately 30%) of pumping equipment and the coincidence of these loads with system summer peak. Through PacifiCorp's irrigation load control program, customers subscribe in advance for specific days and hours when their irrigation systems will be turned off. Load curtailment is executed automatically based on a pre-determined schedule through a timer device. Although a total of 100 MW

[1] Although it may be possible to add control of electric hot water heating to this summer program, this study does not address this option due to the declining saturations of electric hot water heating and the relatively low peak coincident demand during summer.

is contracted with this program, only half is available due to the alternating schedules of program participants. In the Northwest, Bonneville Power Administration (BPA) has run a pilot irrigation program (on a dispatch, rather than scheduled, basis) and Idaho Power has a program similar to that of PacifiCorp.

- **Thermal Energy Storage.** For small commercial and industrial customers, it is possible to have thermal energy storage (TES) cooling systems that produce ice during off-peak periods, which is then used during the on-peak period to cool the building. The system is programmed to use ice-cooling during pre-specified times (typically six hours per day, from April to October) and participants are given incentives on a per-kW or per-ton-of-cooling basis.

Curtailable Rates

Curtailable rate options have been offered by many utilities in the United States for many years. These programs are designed to ease system peak by requiring that customers shed load (in part or whole) by a set amount or to a set level (e.g., by turning off equipment and/or by on-site generation) when requested by the utility. Participants are either provided with a fixed rate discount or variable incentives, depending on load reduction; penalties are often levied for participants who do not respond to curtailment events. Large commercial and industrial customers are the target market for those programs that address PacifiCorp's summer system peak. Many utilities provide a broad range of program options, including Duke Power, Georgia Power, Dominion Virginia Power, Pacific Gas and Electric, ConEd, Southern California Edison, MidAmerican, and Wisconsin Power and Light.

Critical Peak Pricing

Critical Peak Pricing (CPP) rates only take effect a limited number of times during the year. In times of emergency or high market prices, the utility can invoke a critical peak event, where customers are notified and rates become much higher than normal, encouraging customers to shed or shift load. Typically, the CPP rate is bundled with a time-of-use rate schedule, whereby customers are given a lower off-peak rate as an incentive to participate in the program. Customers in all customer classes (residential, commercial, and industrial) may choose to participate in a CPP program, although there are certain segments in the commercial sector that are less able to react to critical peak pricing signals. Currently, there are no CPP programs being offered by Northwest utilities. Peak pricing is, however, being offered through experimental pilots or full-scale programs by several organizations in the United States, notably Southern Company (Georgia Power), Gulf Power, Niagara Mohawk, California utilities (SCE, PG&E, SDG&E), PJM Interconnection, and New York ISO (NYISO). Adoption of CPP has not been as widespread in the Western states as they have in the East. In the Pacific Northwest, this may be partly explained by the generally milder climate and the fact that, due mainly to large hydroelectric resources, energy, rather than capacity, tends to be the constraining factor.

Demand Buyback/Demand Bidding

Demand buyback and/or bidding (DBB) products are designed to encourage customers to curtail loads during system emergencies or high price periods. Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for the energy reduced during each event, based primarily on the difference between market prices and the utility rates. All major investor-owned utilities in the Northwest and Bonneville Power Administration have offered variants of this option, beginning in 2001. PacifiCorp's current program, Energy Exchange, was used extensively during 2001 and resulted in maximum reduction of slightly over 40 MW in that period. Demand reductions from PacifiCorp's current program are approximately 1 MW. Demand buyback products are common in the United States and are being offered by many major utilities. The use of DBB offerings as a means of mitigating price volatility in power markets is especially common among independent system operators including CAISO, NYISO, PJM, and ISO-NE. However, DBB options are not currently being exercised regularly due to relatively low power prices.

II. Valuation of Demand Response Resources

Overview

In the Northwest and elsewhere in the country, valuation of DR programs has been the subject of much debate among utility industry experts. Although there is broad agreement on the existence and relevance of a wide range of benefits arising from DR, there is little agreement on how and to what extent these benefits can be attributed to specific DR programs and what metrics might be used to quantify them. In response to this, in 2005 the Northwest Power and Conservation Council sponsored a series of workshops to identify and enumerate value attributes of DR resources and to develop a consistent methodology for their valuation. The Demand Response Research Center in California recently commissioned two parallel studies to investigate alternative frameworks for valuation and cost-effectiveness analysis of DR products.

As part of this study, we conducted a thorough search of DR literature, evaluation reports, and utility filings, followed by informal interviews with several industry experts to investigate current practices for evaluating DR resources. The results of this analysis are intended to inform PacifiCorp's process for screening DR resource options and how they might be incorporated in its integrated resource plan. We begin this section with a review of potential benefits and value factors ascribed to DR, discuss the current practices and the basis for valuation of these benefits, and then consider alternative approaches for incorporating DR options in the integrated resource planning process.

Benefits of Demand Response

There are many different views on the types and the relative importance of value factors associated with DR. Industry experts agree on at least three general categories of benefits from DR: economic, system reliability, and environmental (Hirst 2001).

Economic Benefits. There is a host of economic benefits to the utility, the consumers, and the power system as a whole that are presumed to arise from DR. Some of these benefits are more tangible and more readily quantifiable than others. Cost avoidance and cost reduction are the main economic drivers for DR. Demand response allows utilities to avoid or defer incurring costs for generation, transmission, and distribution, including capacity costs, line losses, and congestion charges. Economic benefits may also accrue directly to participants in the form of incentives, rate discounts, and greater ability to adjust their loads to prices, thereby gaining greater control over their energy use and managing their energy costs (Braithwait, 2003). DR has also been credited with several harder to quantify economic benefits, such as creating a hedge against market exposure (price objectives), helping create a more elastic demand curve by sending appropriate price signals (elasticity objectives), and reducing the overall market price by alleviating pressure on reserves (market efficiency objectives) (Ruff, 2002).

System Reliability Benefits. Demand response reliability considerations are those meant to ensure reliability in power supply and delivery during system emergencies by providing the ability to shed load under emergency conditions. Customer demand management can enhance reliability of the electric supply and delivery systems by providing the utility with the means to better balance loads with supply during system emergencies and/or high-use periods. In this context, DR can help improve the adequacy and security of the power supply and delivery (T&D) systems by augmenting the utility's ancillary services, such as supplemental reserve (Hirst, 2002).

Potential Environmental Benefits. Demand response resources promote the efficient use of resources in general. Depending on the generation fuel mix of the sponsoring utility, this can help reduce externalities in power generation and reduce emissions. Increasingly, utilities have begun to consider the potential effects of future carbon taxes in their DR product design.

Although this is by no means an exhaustive list of all potential benefits discussed in DR literature, it represents the most common set of benefits recognized by industry experts. Additional benefits such as risk management, market power mitigation, customer service, and third-party benefits (for example to aggregators and service providers) have also been cited as potential benefits of DR. These benefits, however, generally tend to be less pronounced and difficult to quantify (Peak Load Management Alliance, 2002). Approaches and current practices for evaluating DR resources and quantifying each of the above benefit categories are discussed below.

Resource Valuation Methods

Current practices in valuation of DR resources largely rely on an extension of the "Standard Practice Manual" (SPM) originally developed in California for evaluating energy-efficiency programs (California Public Utilities Commission, 2001). Of the four tests set forth in the latest version of the SPM, published in 2001, the total resource cost test (TRC), usually accompanied by the participant test, is the most common method used to screen DR resources by utilities (California Public Utilities Commission, 2003).[2] A clear instance of the application of SPM to the evaluation of DR resources is found in the California Public Utilities Commission's direction that the SPM be used as an option in evaluating DR, "since it allows an assessment of demand reductions from multiple viewpoints: society, customer, utility, and ratepayer."

A review of current practices in valuation of DR benefits indicates that not all benefits discussed above are taken into account by utilities or system operators, mainly due to the fact they tend to be hard to quantify. Potential benefits of DR, common basis for their valuation, and the range of suggested values are summarized in Table 1. Current valuation methods and practices are discussed in greater detail below.

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[2] The other tests are the Ratepayer Impact Measure (RIM) Test, Participant Tests, and the Program Administrator (or Utility) Test.

Table 1. Potential Benefits of Demand Response

Benefit Category	Value Factors	Basis for Valuation	Range of Values
Market-wide	• Overall economic efficiency (better alignment of supply and demand) • Reduction in average price of electricity in the spot market • Reduced costs of electricity in bilateral transactions • Reduced hedging costs, e.g., reduced cost of financial options • Reduced market power • Private entity (e.g. aggregator) benefits	Not Quantified	Not Applicable
Utility System	• Avoided capacity costs (generation) • Avoided energy costs • Avoided T&D losses • Deferred grid system expansion	Benchmarking (peaker unit) Benchmarking (market prices) Adders Marginal (local) T&D costs	$50-$85 Variable 6%-10% Variable
Customer	• Incentives • Reduced power bill (participants) • Greater choice and flexibility	Value of payment Rates, demand charges Cash-flow, Option model	Variable Variable Variable
Reliability Benefits	• Increase in overall system reliability • Value of insurance against low-probability/high-consequence events • Option value (added flexibility to address future events) • Portfolio benefits (increase in resource diversity)	Change in LOLP Value of un-served energy (customer outage costs) Not Quantified Not Quantified	Not Available $3-$5 per kWh Not Applicable Not Applicable
Environmental Benefits	• Avoided emissions • Avoided future carbon taxes	Environmental "adder" Not Quantified	8%-12% Not Applicable

Valuation of Economic Benefits

With the exception of participant tests, the application of the SPM tests rely on the concept of cost avoidance as the key mechanism for taking into account the economic value of DR. The TRC test, which is often used as the primary criterion for screening of DR resources, takes into account a variety of avoided costs associated with generation, transmission, distribution, and line losses. The avoided capacity and, to a lesser extent, energy costs are the principal economic benefits included in the test. Determination of avoided capacity and energy costs are most commonly based on a benchmarking method. In the case of avoided capacity costs, the approach relies on using average per-unit life cycle cost of a peaker resource (usually a combined- or simple-cycle gas turbine) as a benchmark for screening of DR options. Market price curves are the most commonly-used proxy for determination of avoided energy costs.

Avoided capacity costs tend to vary across utilities and the program to which they are applied. Regardless of how they are calculated, capacity costs used by most utilities surveyed fall in the range of $50 to $85 per kW-year. In a recent ruling, the California Public Utilities Commission authorized an avoided cost of $52 per kW as compared to the previously established avoided cost of $85 per kW, based on the average life-cycle cost of a peaker plant method for screening and valuation of DR resources (CPUC, PG&E Application 05-06-028, 2005).

Avoided energy costs represent additional benefits from DR programs. Since most DR programs lead to a shift (rather than a reduction) in energy use, the energy benefits are typically measured in terms of on-peak/off-peak price differential. Other DR programs, such as DLC may result in reductions in energy use, since some portion of the foregone energy use may not be offset by additional consumption during the off-peak period. The latter benefits are especially important in evaluating DR programs from the participants' point of view, since they tend to directly affect bills. Avoided energy costs have been used to measure the benefits in a number of evaluations of DR programs in the Northwest.[3] Avoided energy costs are also the sole basis for determination of payments in demand buyback and demand bidding programs. Indeed, incentives in all demand buyback programs are structured on the basis of market energy prices, rather than avoided capacity costs.

Benefits to the grid system generally fall into two categories: 1) avoided line loss; and 2) value of opportunities to defer system expansion. In the Northwest, both PacifiCorp and PGE have explicitly incorporated avoided T&D losses in their past evaluations of time-of-use and direct load control programs, and Bonneville Power Administration has explicitly included deferral of investments transmission system expansion in its system planning and valuation of DR programs.

Direct benefits to customers represent additional benefits likely to result from DR. These benefits generally appear in the form of incentive payments from the utility or lower bills resulting from reductions in demand charges, shift of demand to lower-priced, off-peak periods and potential energy savings. As discussed above, in the case of DR programs involving a shift in consumption, these benefits tend to be small. In many DR programs, such as time-of-use rates and load control/curtailment programs, portions of the foregone energy use during DR events (high rate or curtailment period) may not be compensated by higher use during off-peak period, thus resulting in net reductions in the customer's energy consumption.

Other potential benefits to customers, such as greater choice and "option value," are generally more difficult to quantify. Attempts at quantification of these benefits generally rely on either a discounted cash-flow analysis or an "option model" (see Sezgen 2005).

Valuation of System Reliability Benefits

The planning and screening of utility-sponsored DR programs typically have not included reliability benefits. But reliability has been the primary metric for valuation of DR programs offered by independent system operators (ISOs). Most of the seven established ISOs have been actively engaged in offering DR options. Since the primary goal of an ISO is to maintain system reliability, it stands to reason that valuation of their programs would be based on reliability

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[3] These include evaluations of irrigation load curtailment and pilot time-of-use programs offered by PacifiCorp, evaluations of residential time-of-use and direct load control programs by PGE, and Bonneville Power Administration's evaluation of remote irrigation load control.

benefits rather than avoided generation capacity. Indeed, evaluations of ISO-sponsored programs completed to date have focused almost exclusively on reliability benefits based on avoided congestion, valued in terms of the location-specific marginal transmission costs (LMC).

The general approach used in valuation of ISO-sponsored DR is based on two factors: 1) the difference between market power price and the DR program costs; and 2) the expected marginal value of increased reliability realized through assumed reductions in loss-of-load probability (LOLP) and its impact on the expected value of un-served energy (EVUE) as a function of the value of lost load (VOLL), that is:

$$EVUE = \text{Value of Lost Load (VOLL)} * \Delta\ LOLP * \text{Load at Risk}$$

The underlying concept in the evaluation approach is that the value of curtailable load (therefore the value of the DR programs that generate it) is a function of the "expectation" of future loss of load. This suggests that the actual value of DR programs stems primarily from their societal value as a hedge against low-probability, high-cost events and the associated outage costs to customers.

The NYISO and ISO-NE have both used this approach in evaluation of their DR products (RLW Analytics, 2005). Calculation of changes in LOLP and the value at risk are generally established on an event-by-event basis and tend to be highly variable. In its evaluations, the NYISO, for example, typically has assumed a VOLL of \$5.00/kWh (NYISO, 2004); and the PJM Interconnection recently proposed a VOLL of \$20/kWh. However, as data on several real-time pricing programs suggest, the VOLL tends to fall in the range between \$3/kWh and \$5/kWh (Barbose 2004, Violette 2006). Available estimates of VOLL are calculated from the customer's or societal perspectives and are generally expressed in terms of energy, rather than capacity. Presumably, given the actual, program-specific hours of curtailment, it may be possible to convert these estimates to an equivalent capacity value.

Valuation of Environmental Benefits

Demand response has the potential to produce tangible environmental benefits by avoiding emissions from the operation of peak units as well as potential conservation effects (load shed versus load shift) during peak periods. Such environmental impacts, however, depend entirely on the emissions profile of the utility's generation resource mix. It is also possible that reduced emissions during peak periods might be offset by increased emissions during off-peak periods, as well as from additional emissions from on-site, back-up generation at commercial and industrial facilities. Due partly to these complexities, potential environmental benefits are not currently being considered in valuation of utility-sponsored DR programs.

Treatment of DR Options in Integrated Utility Resource Planning

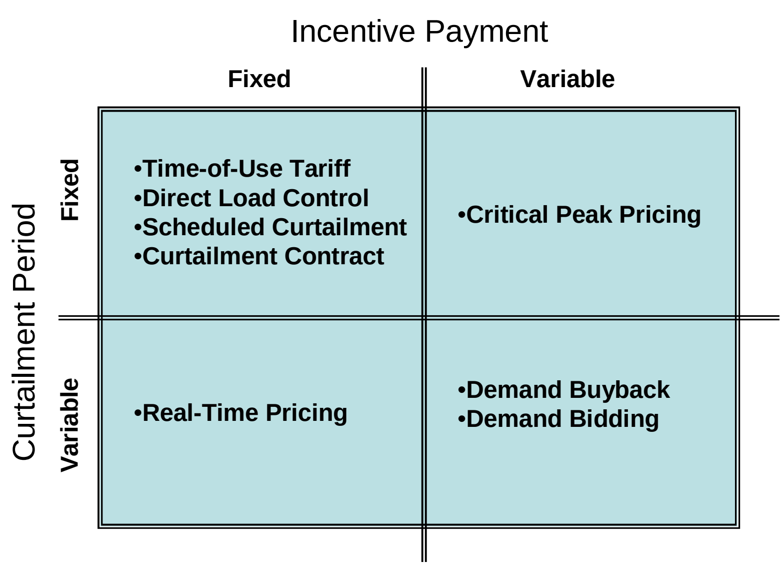
Classification of DR Options

Values arising from DR options, and the manner in which they are incorporated in the integrated planning process may vary by the type of DR product and the entity that sponsors them. There have been several attempts at classification of DR programs. The most common approach to classification of DR involves characterizing them according to the degree of the utility's dispatch control. From this perspective, DR resources are generally categorized according to a "firm" versus "non-firm" dichotomy. Another approach, adopted in the recent report by the U.S. Department of Energy, classifies DR programs in terms of the basis on which participants are compensated and proposes two categories: tariff-based and incentive-based (DOE, 2006). A third approach, suggested in a recent study sponsored by the Rocky Mountain Institute (Rocky Mountain Institute, 2006), classifies DR resources along two dimensions: 1) the criteria that trigger a curtailment request by the utility (economic versus reliability); and 2) the method by which utilities motivate customers to participate in DR (load response versus price response).

These approaches, however, generally do not provide guidance as to how DR benefits and costs might be allocated or how various resources might be modeled in an integrated resource plan. Arguably, from a utility's perspective, the most important benefits of DR are economic (reducing the overall supply cost) and reliability (offering an optional resource in case of system emergencies).

An alternative, and perhaps more appropriate, classification of DR would be in terms of the degree of variability in curtailment period and prices paid by the sponsoring utility.[4] Under this scheme, DR resources are classified in terms of two dimensions: curtailment period and incentive payment. As shown in Figure 1, both period of curtailment and the level of incentives paid by the utility to motivate curtailment may be either fixed or variable. (See Neenan, 2006.)

Figure 1. Classification of Demand Response Programs



[4] Time-of-use rates and critical peak pricing are examples of programs where both pricing period and price levels are fixed. Demand buy-back and demand bidding demand response strategies are examples of programs where both price periods and levels of payment are variable.

Time-of use, load control, scheduled curtailment, and curtailment contracts are examples of resources where both incentive payments and curtailment periods are fixed in advance. Although this group of programs offers more *predictable* prices and, to a lesser extent, amounts of reduction, they also pose a degree of price risk in that program prices are set in advance through the use of price forecasts rather than based on actual prices at the time of load reduction. Demand buyback and demand bidding, on the other hand, are resources where both curtailment period and incentive payments are variable.

Incorporating DR into the IRP Process

Much the same as energy efficiency resources, DR products may be incorporated into the IRP in two ways. The first approach, often referred to as "decrementing," begins with pre-screening of DR resources for general cost-effectiveness based on an external benchmark (generally avoided capacity costs), decrementing the load forecast by the amount of DR resources that pass the screening, and solving for the true avoided cost as derived from the value of decremented load to the resource portfolio. The second approach entails simultaneous modeling of generation and DR resources in the context of an optimization or system expansion planning model and selecting the optimal, least cost, mix of resources. In our view, the latter approach is preferred in that it treats DR resources on a level playing field with supply options and forces the model to select from the most attractive, least-cost mix of resources regardless of their classification as supply or demand-side.

The main shortcoming of these approaches to valuation and integration of DR resources is that they generally focus on economic (cost-reduction) benefits of DR and ignore the reliability benefits. Moreover, the economic benefits of DR often are measured in terms of energy, rather than capacity, values. For most DR resources, the benefits ought to be evaluated primarily in terms of an alternative, "optional" capacity resource and secondary energy benefits (in terms of both reduced consumption and/or peak-off-peak energy costs differential). Regardless of the method used, it is important that the full range of economic values (including avoided capacity, energy, and T&D benefits, as well as reliability benefits) be fully considered in the screening and planning processes. Although the greatest value of DR options is likely to be on the generation side, additional benefits such as avoided T&D losses and reliability benefits may be incorporated in the valuation as utility-specific "adders."

An additional shortcoming of these approaches is that they ignore the role of risk and uncertainty associated with various resource options. Clearly, there are technical (e.g. equipment failure) and market (e.g. program and event participation rates) uncertainties inherent in any demand-response option. These risks need to be explicitly taken into account in screening of DR resources. It is equally important in the context of IRP that the treatment of DR risks be symmetrical; that is, the screening process ought to also take into account upside risks of DR. Since DR resources are valued on the basis of expected future loads and power prices, future fluctuations in loads and avoided costs are likely to have a direct effect on the value of DR options.[5]

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[5] Portfolio management principles and techniques are being used in a limited way by some utilities to analyze uncertainties in the IRP process. This is particularly the case in designing standard renewable portfolios in several

In the context of IRP, joint consideration of economic (capacity and energy) and reliability benefits does, however, pose additional complexity. Since integrated resource planning processes are generally based on long-run resource needs, the value of DR hinges on its ability to displace some portion of the utility's peak demand. As pointed out in the Department of Energy's recent report, once DR resources are included in the utility's capacity resource mix, they become part of the planned capacity and are no longer available for dispatch during system emergencies (DOE, 2006). It is important, therefore, to distinguish between DR resources that serve the economic objectives and might be incorporated in the resource plan and those that are more appropriately set aside for reliability purposes. Certain DR resources, such as demand bidding or demand buyback, may be set aside as reliability options to be called upon during system emergencies.

Potential adverse customer impacts are additional considerations in DR planning. Clearly, once DR resources are incorporated in the planned capacity, the utility can maximize the value of DR resources by exercising these options to the maximum extent possible. However, the more frequently these options are exercised, the higher the likelihood of more severe disruptive impacts of the customers' operations. This will affect the customers' decision to participate in the DR program and thus reduce the market potential for DR.

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jurisdictions. For a discussion of uncertainty in IRP and the portfolio management approach see Awerbuch (1993 and 2005). Also see Bolinger (2005) for a survey of current utility practices in portfolio design.

III. Demand Response Resource Potentials

The approach to estimation of resource potentials in this study distinguishes between three definitions of demand-response potential that are widely used in utility resource planning: technical, market, and achievable potentials. Technical potential assumes that all demand-response resource opportunities may be captured regardless of their costs or market barriers, notwithstanding obvious exceptions such as load control in mission-sensitive operations. Market potential, on the other hand, represents that portion of technical potential that is likely to be available over the planning horizon, given resource constraints and prevailing market barriers. Finally, achievable potential recognizes that not all of the market potential can be implemented due to the overlap (or interaction) among DR options targeted for the same sectors and/or end uses.

To the extent possible, we have sought in this study to obtain the most recent and reliable data on market prospects for various DR options, relying upon available resources from other utilities offering similar products. However, information and assumptions based on current demand response experiences and costs, no matter how accurate, are subject to future uncertainty. Therefore, the results of this study are to be viewed as preliminary and indicative rather than conclusive.

The general methodology and analytic techniques used in this study conform to standard practices and methods used in the utility industry. Given the scope and timeframe of this study, it was necessary to utilize a consistent and relatively simple methodology to effectively address PacifiCorp's immediate IRP needs. The methodology and inputs assumptions are fully described in Sections IV and V of this report.

Technical Potential

In the context of demand response, technical potential assumes that all applicable end-use loads, in all customer sectors, are at least partially available for curtailment, except those customer segments (e.g., hospitals) and end uses (e.g., restaurant cooking loads) that do not lend themselves to curtailment,[6] and for those programs (e.g., direct load control) that utilize cycling strategies.

Table 2 provides for each customer class (industrial, commercial, irrigation and residential) the technical potential in MW at the system level. (Separate results for the East and West control areas are provided in Appendices 1 and 2.) From a strictly technical perspective, critical peak pricing is expected to have the largest potential due to its broad-based eligibility, followed by curtailable rates and demand buyback. In the absence of market constraints, these figures should

[6] Although hospitals generally rely on some on-site generation capability, which may be called upon by the utility as a dispatchable resource, such resources are not being considered in this study. Arguably these units are likely to be needed by the host facility during the same period as the utility and are therefore unlikely to be made available for dispatch.

be viewed largely as estimates of "technical feasibility" only and a measure of the total load that is technically available for demand response.

Table 2. Technical Potential (MW), System

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	194	- - -	- - -	510	531	500
Commercial	- - -	55	50	-	93	133	232	130
Irrigation	- - -	- - -	-	381	- - -	- - -	- - -	- - -
Residential	374	351	-	- - -	- - -	- - -	618	- - -
Total	***374***	***406***	***244***	***381***	***93***	***642***	***1,380***	***630***
% of System Peak	*4%*	*5%*	*3%*	*5%*	*1%*	*8%*	*16%*	*7%*

To provide an illustration of the methods used to estimate technical potentials, the fully dispatchable winter program will be used. First, eligibility for this program is limited to residential customers due to low saturation of electric space and water heating in other customer classes. Next, PacifiCorp energy sales and system and end-use load shapes indicate that the total residential space and water heating loads during the top 87 hours of the winter average approximately 580 MW and 250 MW, respectively. Although DLC programs can fully interrupt this load when installed, it is assumed that a 50% cycling strategy is used, and only 90% of this is technically available to account for the fact that not all systems can be retrofitted with DLC equipment. Therefore, the system-level technical potential, as shown in Table 3, is 374 MW.

Market Potential

Market potential is the subset of technical potential that may reasonably be accessible by program strategies, accounting for market barriers and customers' ability and willingness to participate in demand response programs. For the majority of demand response options, market potentials are estimated by adjusting technical potential by two factors: expected rates of "program" and "event" participation. For all programs options, estimates for both program and event participation are derived based on the experiences of PacifiCorp and other utilities offering similar programs. In the case of curtailable rates and demand buyback, market potentials are estimated based on observed price elasticity of load response. See Figure 2 for a comparison of technical and market potentials for various program options.

As shown in Table 3, curtailable rates have the highest market potential (144 MW), followed by summer DLC and irrigation.

Figure 2: Technical and Market Potential (MW), System

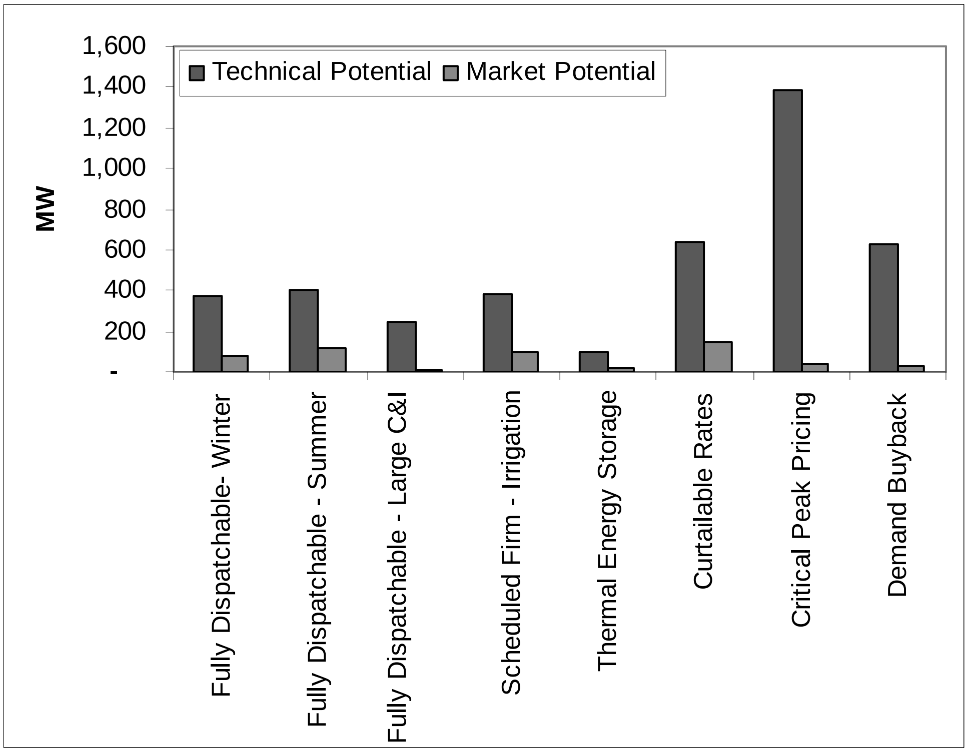


Table 3. Market Potential (MW), System

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	5	- - -	- - -	115	14	22
Commercial	- - -	3	1	- - -	19	30	6	6
Irrigation	- - -	- - -	- - -	95	- - -	- - -	- - -	- - -
Residential	75	118	- - -	- - -	- - -	- - -	17	- - -
Total	***75***	***120***	***7***	***95***	***19***	***144***	***37***	***28***
% of System Peak	*0.9%*	*1.4%*	*0.1%*	*1.1%*	*0.2%*	*1.7%*	*0.4%*	*0.3%*

For a fully dispatchable winter program, an expected load participation rate of 20% (based on experience of similar programs) and event participation rate of 100% are assumed. This assumption is based on the fact that, absent customers' ability to override curtailment and no equipment failure, load interruption would occur once the load is dispatched by the utility.[7]

[7] Reliability of direct load control systems is primarily a function of the type of equipment and communication systems used to affect control such as radio frequency, telephone networks, wide-area networks, or power line carrier systems. Historical experience with systems has shown that the assumption of a zero failure rate may be unjustified.

Based on these assumptions, this program could reasonably be expected to provide approximately 75 MW of load reduction for the PacifiCorp system.

Using price elasticity of load participation and a measure of commercial and industrial customers' willingness to participate in demand buyback, market potential for this option is estimated at 28 MW. As discussed in Section IV of this report, the elasticity estimates were calculated based on data available on 2000-'01 demand buyback program experience of Northwest utilities. Data available on PacifiCorp's 2000-'01 Energy Exchange program indicate approximately 40 MW of reduction at an average cost of approximately $100 per MWh. The estimated 28 MW of future market potential may prove overly optimistic due to the dramatically different market conditions prevailing today. Reductions similar to those achieved in 2000-'01 could be difficult or impossible to repeat if electricity prices and customer concerns over energy market conditions continue to be low. Indeed, based on PacifiCorp's program records, operation of the Energy Exchange program during the past three years has resulted in a maximum reduction of no more than 1 MW.

Achievable Potentials

In analyzing levels of achievable potential it is important to take into account two factors: resource interactions and load reduction being achieved given existing programs. Achievable potentials, therefore, represent unique impacts of various DR program options net of the impacts of existing programs. Estimates of market potentials presented above provide "stand alone" estimates of potential. In calculating achievable potential, it is also important to take into account the interaction among DR programs that target the same customer sector and/or end uses within the same sector. Generally, interaction may be accounted for by first ranking competing programs by levelized cost and then allocating the market potentials based on an "availability" factor[8].

For the purpose of this study, we have assumed that DBB and scheduled firm irrigation are fully available; therefore they have been assigned an availability factor of 100%. Since curtailable rates and dispatchable large C&I compete for the same target market as DBB, only a portion of their market potential will be available. In the residential and small commercial sector, the summer DLC program is fully available; however, thermal energy storage would only be partially available as it competes with the commercial sector DLC program option.

As shown in Table 4, the DR options considered in this analysis may be expected to provide 373 MW of capacity for the PacifiCorp system. In 2005, the PacifiCorp system peaked at 8,940 MW with 570 MW and 1,540 MW of load occurring during the top one percent and ten percent of the load duration curve. The estimated achievable potentials for DR provide the opportunity to offset 66% of the top one percent and 25% of the top ten percent of the system peak load.

[8] Technically, this is the percentage of the market potential that remains after accounting for resource interactions. For example, a 25% availability factor would be multiplied by the market potential to arrive at the achievable potential on a program-by-program basis.

Summer DLC (120 MW), irrigation (95 MW), and curtailable rate (72 MW) are expected to provide the highest levels of achievable potential. Yet, approximately 114 MW of the identified potential is already under contract through PacifiCorp's Cool Keeper (65 MW), irrigation load curtailment (48 MW), and Energy Exchange (1 MW), resulting in a remaining achievable potential of 259 MW. Therefore, in addition to achievable potential, Table 4 also provides potential net of current programs.

Table 4. Achievable Potential (MW) – System

	Fully Dispatchable			Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Achievable Potential	37	120	3	95	9	72	7	28	**373**
Current Program MW	- - -	65	- - -	48	- - -	- - -	- - -	1	**114**
Potential Net of Current Programs	**37**	**55**	**3**	**47**	**9**	**72**	**7**	**27**	**259**

Proxy Resource Supply Curves

Supply curves are constructed to show the relationship between the cumulative quantities of DR resources and their costs. Development of supply curves first requires the estimation of per-unit costs. Demand response strategies vary significantly with respect to both type and cost levels. Applicable resource acquisition costs for DR generally fall into two categories: 1) fixed direct expenses such as infrastructure, administration, maintenance and data acquisition; and 2) variable costs. In the category of fixed cost, this study distinguishes between initial development and on-going program administration and operation costs. Variable costs also fall into two categories: costs that vary by the number of participants (e.g., hardware costs) and those that vary by kW reduction (primarily incentives).

Although a large number of national programs were researched for this project, the reporting of costs, particularly development and ongoing administrative costs, were found to be either unavailable or difficult to measure. For the purposes of this study, to the extent possible, we have relied primarily on administrative costs associated with PacifiCorp's other, similar programs, or have adopted rough estimates available from other utilities. See Section IV for specific cost assumptions for various DR options.

In developing proxy supply curves, all program costs were first allocated annually over the expected program life cycle (10 to 15 years) discounted by PacifiCorp's real cost of capital at 5.1% to estimate the per-kW levelized[9] costs for each resource. Resources were then ranked based on their levelized costs along the supply curve. Figure 3 displays per-unit costs for the various DR options.

[9] Levelized costs represent the annual contract cost, per kW/year, for each DR option. This approach provides means for treating all DR on a consistent basis with supply alternatives in the IRP framework.

Figure 3: Levelized Resource Costs ($/kW/year)

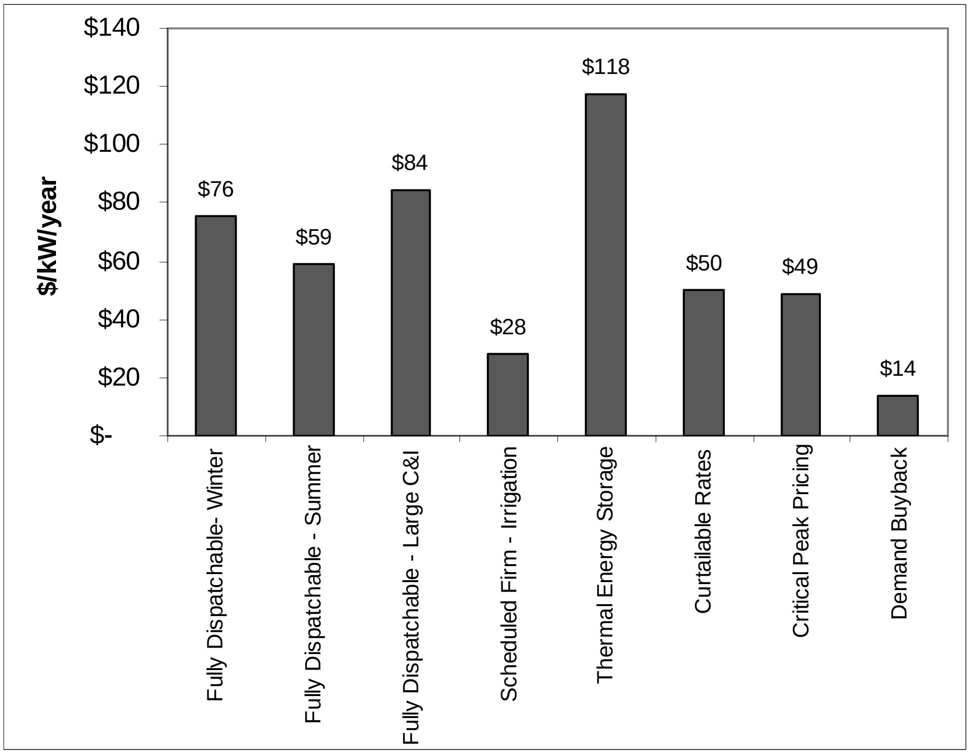
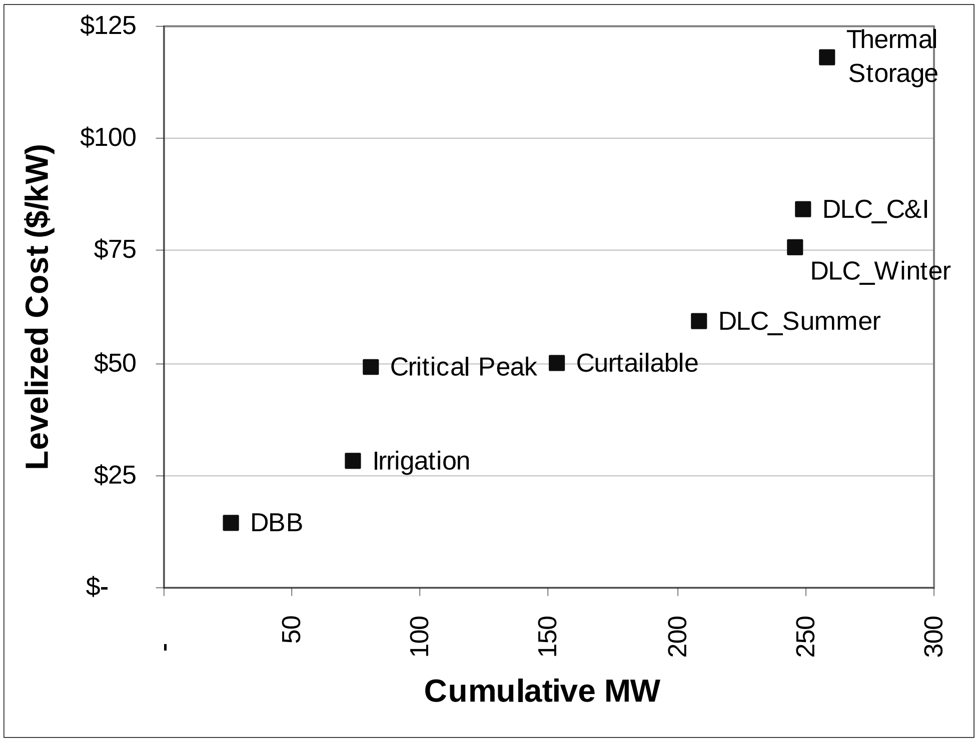


Figure 3 indicates that, with the exception of the irrigation program, per-unit costs tend to increase with the level of firmness of the load: the more reliable the load reduction, the more costly the program. Demand buyback, at $14/kW/year, is expected to be the least expensive option. This program, although relatively inexpensive, provides possibly the least reliable load reduction among the eight program options.

Firm irrigation is the next lowest-cost resource at $28/kW/year. Because reductions by this program are pre-determined and scheduled, it is an effective program for achieving firm seasonal load reductions. However, its value as a reliability option is limited because 100% capacity reductions are already incorporated into the utility's planned resource capacity, and hence cannot be "called" to provide load relief during system emergencies. Critical peak pricing ($49/kW/year) provides the ability to notify customers of curtailment events; national experience indicates the potential for reductions can be significant, but customer acceptance and response have generally been lower than expected. Curtailable rate programs ($50/kW/year) may provide additional dependability due to contract requirements on customers and may serve as an effective option for reliability purposes. Owing mainly to hardware costs and incentives required of fully dispatchable resources, per-unit costs for the three direct load control programs exceed $59/kW/year. Finally, thermal energy storage is expected to be the most costly option with a per-unit cost of $118/kW/year.

The proxy supply curve for the eight resource options investigated in this study was constructed based on estimated achievable resource potential net of current programs and per-unit cost of each resource option. Figure 4 displays graphical presentation of the supply curve, which represents the quantity of resources (cumulative MW) that can be achieved at or below the cost at any point. Cumulative MW is created by summing the achievable potential net of current programs along the horizontal axis sequentially, in the order of their levelized costs. For example, the irrigation program has 47 MW available, and its cost is second lowest. Therefore, its quantity is added to the 27 MW of DBB, showing that in total, 74 MW of resources are available at prices equal to or less than $28/kW.

Figure 4. Cumulative Supply Curve, System



Resource Potential Scenarios

High and Low

For the purpose of IRP modeling, achievable potentials were estimated under three scenarios: base case, high, and low, corresponding with PacifiCorp's projected on-peak market prices of $40/MWh (low), $60 (base) and $100 (high). To account for the relationship between market prices (and incentives) and program potential, high scenarios generally assume aggressive marketing efforts and higher incentive levels and, therefore, higher program participation. The low scenario reflects a less aggressive marketing effort and relatively weak program participation. (See Sections IV and V for assumptions underlying the two scenarios.)

The high and low scenarios for the DBB and curtailment contract options were constructed based on load response elasticity estimates. As reported in the 2006 Department of Energy's Report to Congress, commercial and industrial customers have typically exhibited an inelastic response to prices (elasticity = 0.1) in load curtailment. This figure was used as a basis for the high and low program participation scenarios for the fully dispatchable large commercial and industrial and curtailable rates options. For the DBB program, a price elasticity of 1.45, estimated based on the 2000-2001 regional data on demand buyback programs, was used to develop the high and low scenarios. (See Section IV for a discussion of methodology and data.)

The results for the three scenarios are shown in Table 5. Generally, as the potential increases, so does the per-unit costs, due to higher incentives and marketing costs. Yet, in a few cases, such as critical peak pricing and fully-dispatchable commercial and industrial programs, per-unit costs are expected to fall from the low to the base case due to economies of scale; lower marginal per-unit costs result from the fact that fixed program costs are spread over a larger number of units.

Table 5. High, Base, and Low Costs and Quantities System

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Low								
Achievable Potential MW	19	80	1	76	7	30	1	9
Resource Costs ($/kW/yr)	$58	$53	$167	$29	$115	$39	$91	$13
Base								
Achievable Potential MW	37	120	3	95	9	72	7	28
Resource Costs ($/kW/yr)	$76	$59	$84	$28	$118	$50	$49	$14
High								
Achievable Potential MW	56	141	9	114	12	88	14	65
Resource Costs ($/kW/yr)	$84	$72	$102	$37	$119	$86	$45	$18

Treatment of Metering Costs

The DR scenarios presented above include metering costs, where applicable (please see Section V for detailed assumptions). In the future, these costs may not be necessary if advanced metering technology is implemented in PacifiCorp's territory. Therefore, this additional scenario excludes metering costs from the base estimates of per unit cost. Figure 5 below displays the new figures and Table 6 provides a comparison of the base (with metering) scenario and the alternative (without metering). The exclusion of meter costs makes little difference (less than $1/kW/year) in all programs, except critical peak pricing where the reduction equals $7 /kW/year.

Figure 5. Per Unit Resource Costs – Excluding Metering Costs

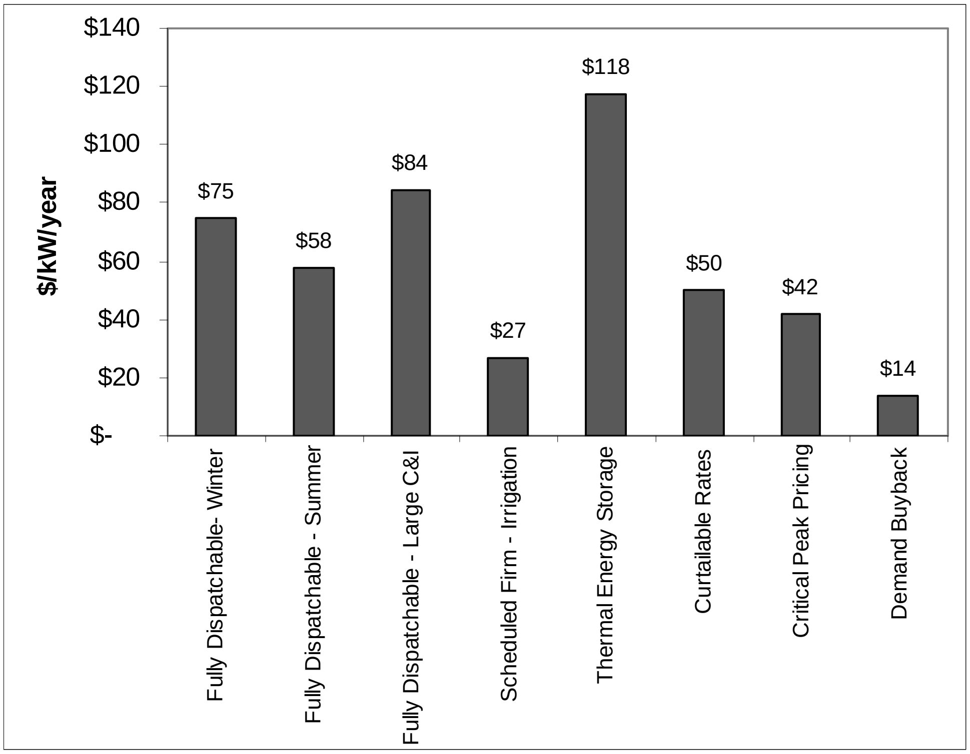


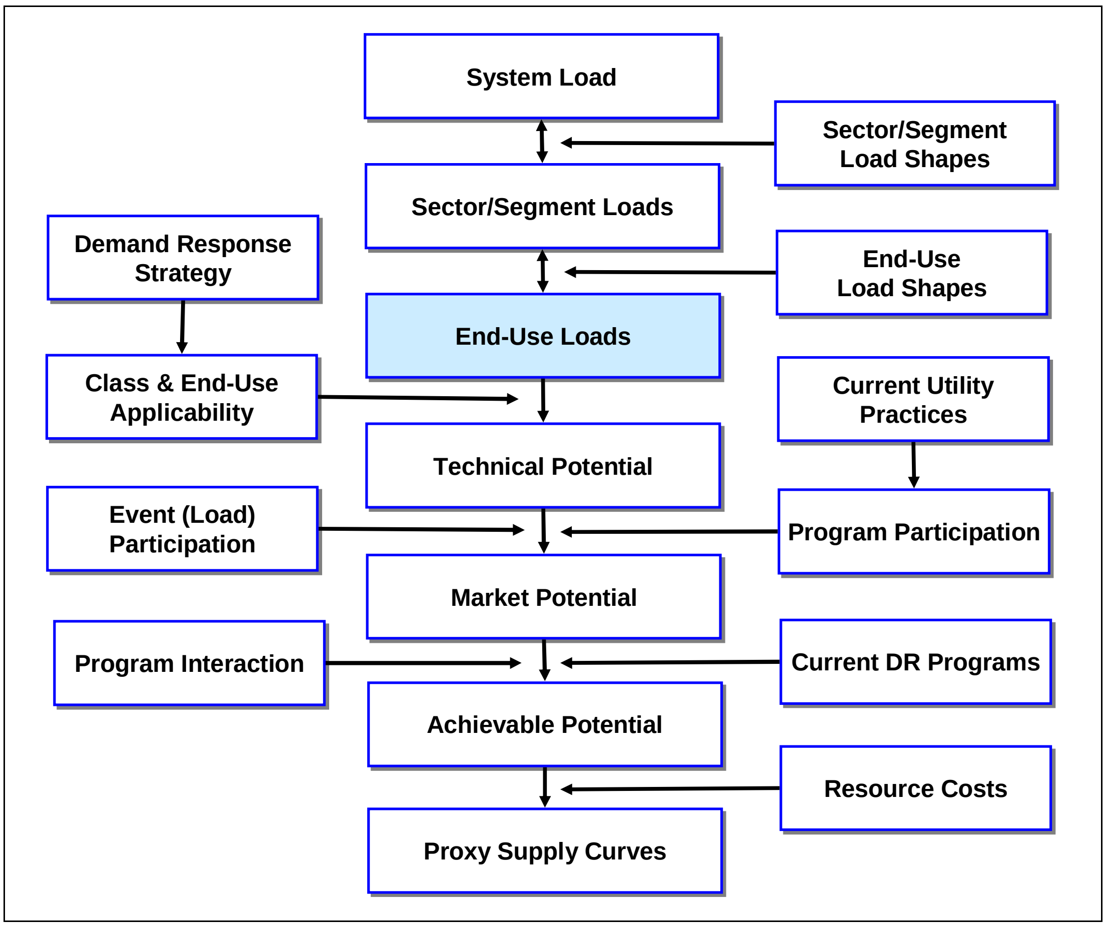
Table 6. Comparison of Costs with and without Metering Costs

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
With Meter Costs ($/kW/year)	$76	$59	$84	$28	$118	$50	$49	$14
Without Meter Costs ($/kW/year)	$75	$58	$84	$27	$118	$50	$42	$14

IV. Methodology and Data

The development of proxy supply curves requires both reasonable approximations of available quantities and reliable estimates of procurement costs for each DR resource. With respect to quantities, the overall approach in this project (see Figure 6) distinguishes between three definitions of DR resource potential that are widely used in utility resource planning: *technical*, *market*, and *achievable*. Load shapes for the PacifiCorp system, East/West regions, customer segments, and end use load shapes combine with sales data to produce hourly load profiles. For each DR strategy, technical potential is estimated by applying end use and sector applicability, while market potential additionally incorporates program and event participation. Achievable potential estimates also consider interactions among programs and current DR offerings at PacifiCorp. Finally, proxy supply curves show the relationship between achievable potential and the expected per-unit cost of each strategy.

Figure 6. Schematic Overview of Methodology



Data Requirements and Sources

Development of DR supply curves requires the compilation of a large and complex database on load data, end-use and appliance saturations, demand response impacts, and costs, gathered from multiple sources. To the greatest extent possible, this study relies on data available from PacifiCorp on loads, sales, end-use load profiles, and estimates of administrative costs. Secondary data sources were utilized for estimates of DR program impacts. Specific data elements and their respective sources are listed in Table 7.

Table 7. Data Elements and Sources

Data Element	Source – Various Years
Total Sales by Customer Class	PacifiCorp, 2005, Table A
Commercial Segmentation	PacifiCorp, 2005, Commercial Survey (by participants)
Hourly System and Regional Load Profiles	PacifiCorp, 2005
End-Use Shares and Load Shapes	EIA, Commercial Buildings Energy Consumption Survey (CBECS) EIA, Residential Energy Consumption Survey (RECS) Northwest Power Planning Council PacifiCorp PGE Quantec Load Shape Library
Existing PacifiCorp Demand Response Programs	PacifiCorp studies, various years
Demand Response Impact Estimates	PacifiCorp, California Energy Commission, Peak Load Management Alliance (PLMA), Edison Electric Institute (EEI), Lawrence Berkeley National Laboratories (LBNL), Various RTO and Utility Reports, Department of Energy
Demand Response Program Costs	PacifiCorp, Other Utilities, Regional Transmission Organizations

Methodology for Estimating Technical Potential

Within the context of demand response, technical potential assumes that all applicable end-use loads, in all customer sectors, are at least partially available for curtailment, excepting those customer segments (e.g., hospitals) and end-uses (e.g., restaurant cooking loads) that clearly do not lend themselves to curtailment.

Demand response options are not equally applicable to or effective in all segments of the electricity consumer market, and their impacts tend to be end-use specific. In recognition of this fact, this methodology employs a "bottom-up" approach, which involves first breaking down system loads for each of PacifiCorp's two control areas into sectors, market segments within each sector, and applicable end uses within each market segment. Demand response potentials are estimated at the end-use level and then aggregated to sector and system levels. This approach is implemented in four steps as follows.

1. ***Define customer sectors, market segments, and applicable end-uses***. The first step in the process involves defining appropriate sectors and market segments within each sector. Given the available data, this study includes four customer classes (residential, commercial, industrial, and irrigation), the eleven commercial segments defined in

Commercial Building Energy Consumption Survey (Education, Food Stores, Hospitals, Hotels/Motels, Other Health, Offices, Public Assembly, Restaurants, Retail, Warehouses, and Miscellaneous), and total industrial loads.

2. ***Create sector and segment load profiles***. Using available local hourly load profiles, service area sales are used to generate sector- and segment-specific load shapes. Figure 7 displays the load duration curves for East, West and System overall, and Figure 8 shows the typical daily system load profiles. Figure 9 exhibits sector load shapes; the "System" shown is the actual load and "Total Sector" is the sum of load by sector. The difference between these lines are due to loads that are not amenable to demand response, such as traffic and street lighting, and loads not directly attributable to end use load profiles.

Figure 7: PacifiCorp Load Duration Curve, 2005

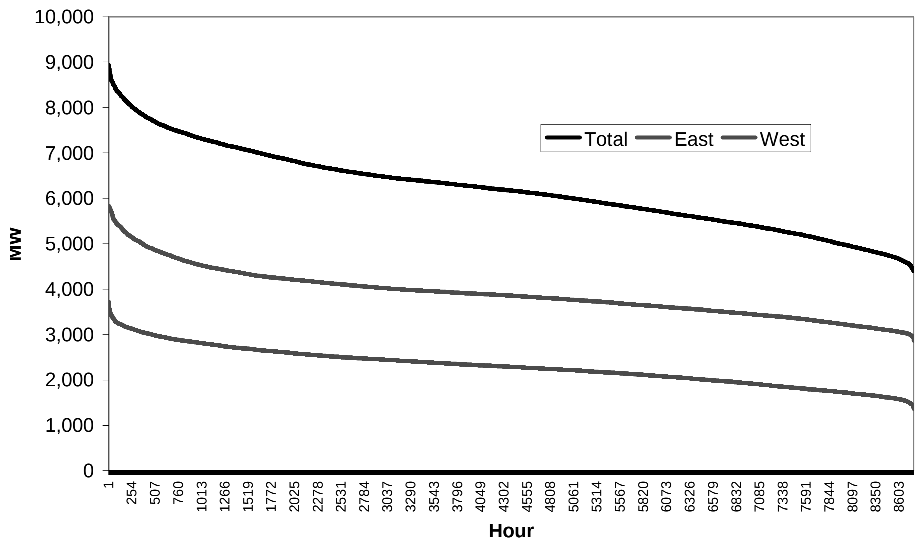


Figure 8: Typical Daily (Week-Day) Seasonal Load Profiles by System and Control Area

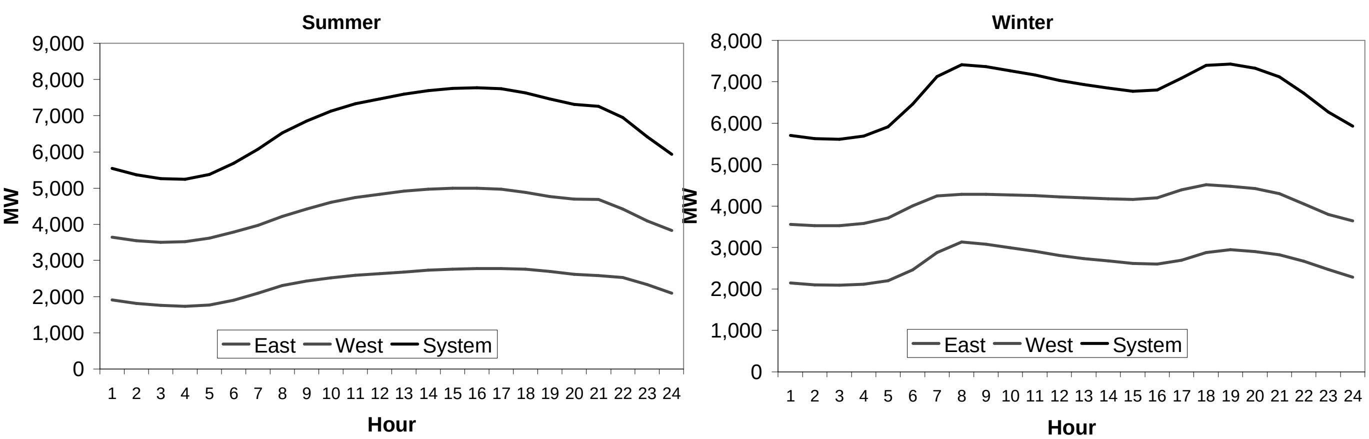
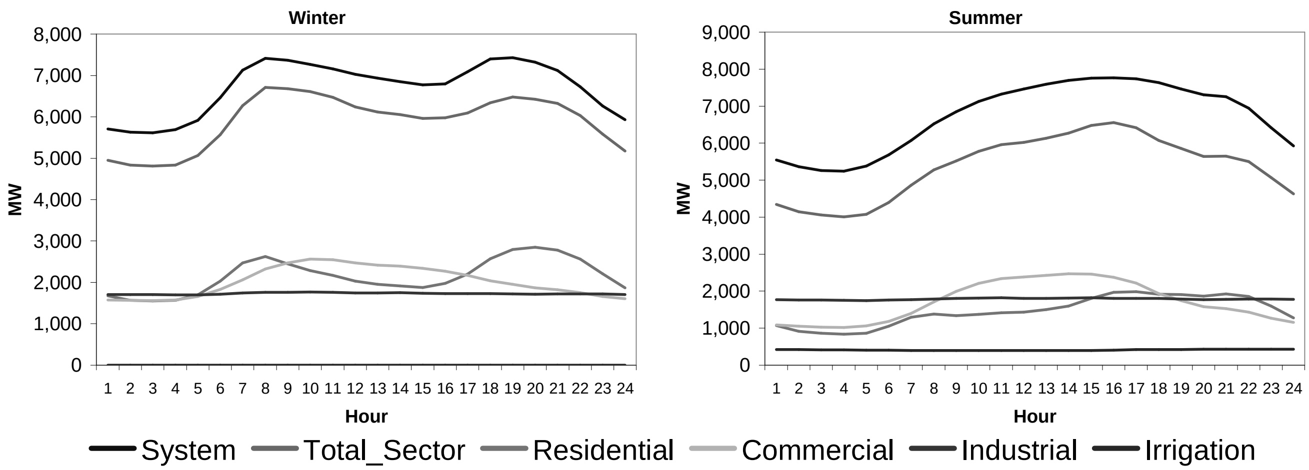


Figure 9: Typical Daily (Week-Day) System Load Profiles by Sector



3. ***Develop sector- and segment-specific typical peak day load profiles for each end use.*** "Typical" daily profiles are developed for each end-use within various market segments. Contributions to system peak for each end-use are estimated based on end-use shares available from PacifiCorp or regional estimates, available through EIA energy use surveys. Figure 10 and Figure 11 display the end-use contributions, summarized across sectors, to system load.

Figure 10: End-Use Contributions to System Load- Summer

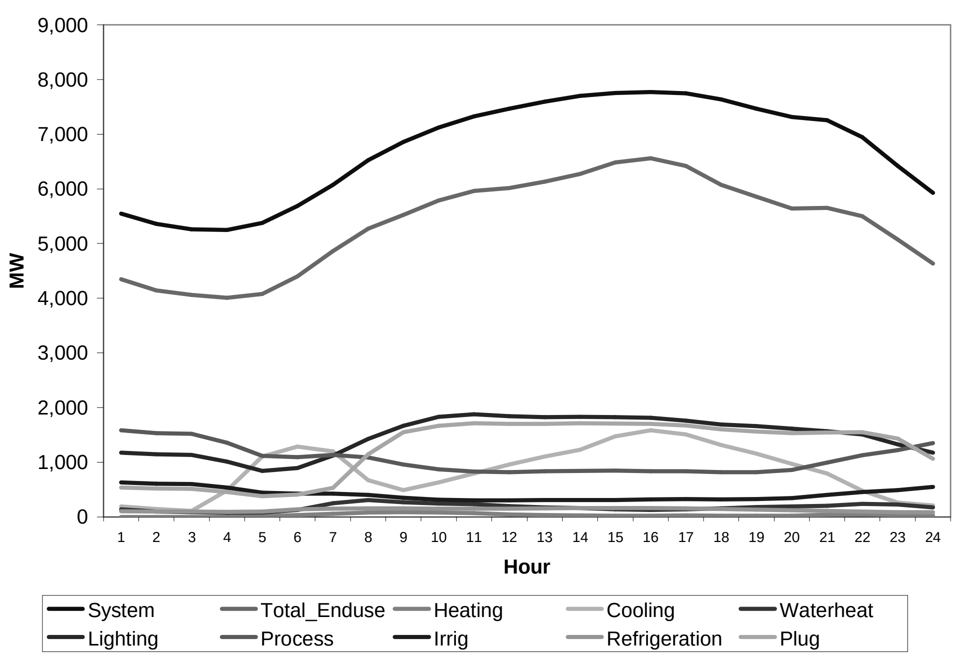
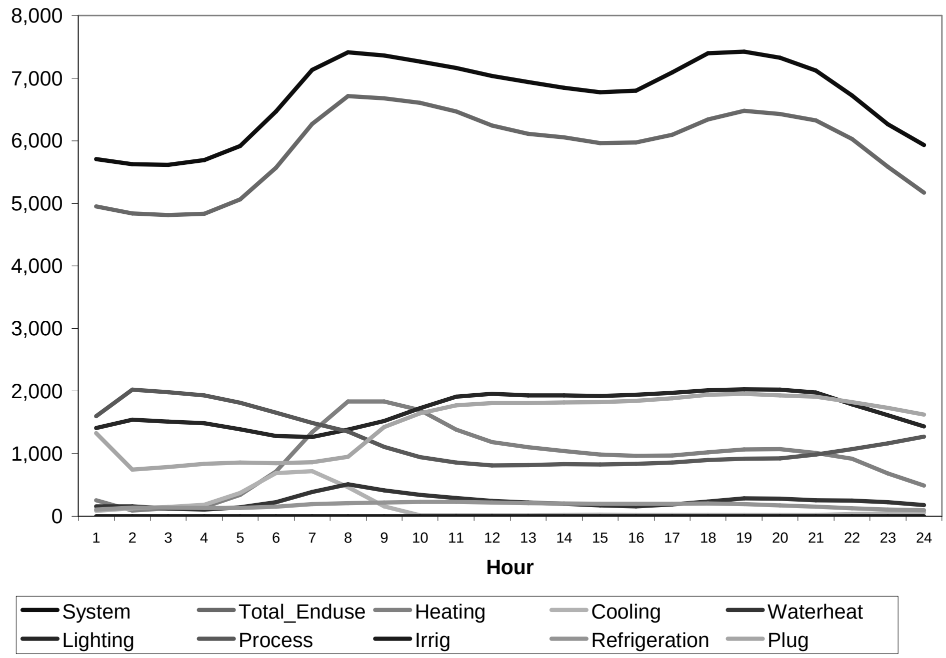


Figure 11: End-Use Contributions to System Load- Winter



4. ***Estimate technical potential***. Technical potential for each demand response strategy is assumed to be a function of customer eligibility in each class and the expected impact of the strategy on the targeted end-uses. Analytically, technical potential (*TP*) for demand-response strategy *s* is calculated as the sum of impacts at the end-use level (*e*), generated in customer sector (*c*), by the strategy (*s*), that is:

$$TP_s = \sum TP_{sce}$$

and

$$TP_{sce} = LE_{cs} \times LI_{se}$$

where,

- LE_{cs} (load eligibility) represents the percent of customer class loads that are eligible for strategy *s*
- LI_{se} (load impact) is percent reduction in end-use load *e* resulting from strategy *s*

Load eligibility (LE_{cs}) thresholds are established by calculating the percent of load by customer class and market segment that meet load criteria for each strategy. Table 8 outlines the portion of load that is eligible for program strategies. (Section V provides detailed program-specific assumptions.)

Estimates of maximum load impacts, resulting from various demand response strategies (LI_{se}), are derived from the commercial and industrial Enhanced Automation Study sponsored by the California Energy Commission, studies by Lawrence Berkeley National Laboratories (e.g., Goldman, 2004), and the experiences of PacifiCorp and other utilities with similar DR programs. Table 9 outlines these inputs; detailed assumptions are found in the following section.

Table 8: Eligibility by Sector and Program

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	100%	100%	- - -	- - -	- - -	-	100%	-
Education	- - -	- - -	19%	- - -	- - -	50%	100%	50%
Food Stores	- - -	- - -	27%	- - -	- - -	70%	100%	70%
Hospitals	- - -	- - -	- - -	- - -	- - -	-	-	-
Hotels/Motels	- - -	20%	5%	- - -	20%	12%	100%	12%
Other Health	- - -	7%	23%	- - -	7%	60%	-	60%
Miscellaneous	- - -	- - -	- - -	- - -	- - -	-	-	-
Offices	- - -	10%	19%	- - -	10%	50%	100%	50%
Assembly	- - -	10%	8%	- - -	10%	20%	-	20%
Restaurants	- - -	50%	- - -	- - -	50%	-	-	-
Retail	- - -	12%	- - -	- - -	12%	-	-	-
Warehouses	- - -	13%	15%	- - -	13%	40%	-	40%
Industrial	- - -	- - -	30%	- - -	- - -	80%	100%	80%
Irrigation	- - -	- - -	19%	100%	- - -	50%	-	-
Eligibility Criteria	Residential	Residential and Small Commercial (<30 kW)	Large C&I - >250 kW with EMS	Irrigation only	Small Commercial	Large C&I - >250 kW	No Load Threshold	Large C&I - >250 kW

Table 9: Technical Load Impacts

Program Name/Sector	Fully Dispatchable				Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter		Summer	Large C&I					
End Use	**Space Htg**	**Hot Water**	**Cooling**	**Total**	**Process**	**Cooling**	**Total**	**Total**	**Total**
Residential	90%	90%	90%	- - -	- - -	- - -	- - -	25%	- - -
Education	- - -	- - -	- - -	22%	- - -	- - -	22%	25%	22%
Food Stores	- - -	- - -	- - -	20%	- - -	- - -	20%	25%	20%
Hospitals	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Hotels/Motels	- - -	- - -	90%	20%	- - -	90%	20%	25%	20%
Other Health	- - -	- - -	90%	8%	- - -	90%	8%	- - -	8%
Miscellaneous	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Offices	- - -	- - -	90%	32%	- - -	90%	32%	25%	32%
Assembly	- - -	- - -	90%	20%	- - -	90%	20%	- - -	20%
Restaurants	- - -	- - -	90%	- - -	- - -	90%	- - -	- - -	- - -
Retail	- - -	- - -	90%	- - -	- - -	90%	- - -	- - -	- - -
Warehouses	- - -	- - -	90%	30%	- - -	90%	30%	- - -	30%
Industrial	- - -	- - -	- - -	30%	- - -	- - -	30%	25%	30%
Irrigation	- - -	- - -	- - -	30%	90%	- - -	30%	- - -	30%

Methodology for Estimating Market Potential

Market potential is the subset of technical potential that may reasonably be implemented, taking into account the customers' ability and willingness to participate in load reduction programs, subject to their unique business priorities, operating requirements, and economic (price) considerations. Market levels of potential are derived by adjusting technical potentials by two factors: expected rates of *program* and *event* participation. Market potential (*MP*) is calculated as the product of technical potential, sector program participation rates (PP_c), and expected event participation (EP_c) rates:

$$MP_s = TP_{sc} \times PP_c \times EP_c$$

Rates of program and event participation are estimated based on the recent experiences of PacifiCorp and other utilities, as well as those of Regional Transmission Organizations (RTOs) that have offered similar programs. Table 10 outlines the estimates of program and event participation; referenced assumptions are found Section V.

Table 10: Program and Event Participation Inputs

	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Program Participation	10%	20%*	3%	50%	20%	25%	3%	35%
Event Participation	100%	100%	90%	50%	100%	90%	90%	13%

* Represents residential sector; commercial sector is assumed to be 5%

Utility customers' willingness to participate in DR programs (or "market potential") is itself a function of price and non-price factors. Non-price factors generally depend on specific operational constraints that may impede participation in DR. These are generally difficult to quantify and may only be determined through rigorous market studies.

Price-induced effects, particularly for market-based DR strategies, can, however, be estimated explicitly by calculating price elasticity of load response, based on empirical data, using the following general formulation of price elasticity:

$$LogN(MW) = \alpha + \beta \,\mathrm{LOG}(P),$$

where *MW* is the quantity of demand reduction commitment during each curtailment event and *P* represents the offer prices (incentives) from the utility.

Since the equation is specified in logarithmic form, β is a direct measure of elasticity, indicating percent change in load commitment that may be expected to result from a one percent change in incentives.

To estimate the parameters of the above model, data were collected on the 2000-2001 experience of four major utilities in the Northwest (PacifiCorp, PSE, PGE, and Avista) on their demand buyback programs. The estimated parameters of the model are shown below.

$$LogN(MW) = -0.5 + 1.45\ (3.0)\ \mathrm{LogN}(P)$$

The calibration of the demand model resulted in a price coefficient of 1.45 with a t-statistic of 3.0, indicating that the estimated coefficient is statistically significant at the 95% level of significance or better. The estimated parameter for the price variable shows that for every one percent change in price, load response is expected to change by 1.45%, indicating a moderately elastic response. The statistical parameters of the estimated model are shown in Table 11, below.

Table 11. Estimation Results of the Elasticity Model

Variable	Estimated Parameter	t-Statistic
Intercept (α)	-0.5	
LogN (Price)	1.45	3.0
Number of Observations: 13		

$R^2 = 0.65$

The elasticity estimate obtained from the data is higher than expected. There have not, however, been any other studies of response elasticity for demand buyback or demand biding programs. Additionally, slight changes in the specification of the above quantity/price relationship, introduced by using alternative data frequency levels, such as daily or monthly, are likely to alter the parameter estimates. For example, daily, event-by-event data, available from Puget Sound Energy for 2000-2001, resulted in a significantly lower elasticity of 0.45. Unfortunately, event-by-event data were not available for all four utilities. Such data, we expect, would likely have produced a more robust and reliable estimate of price elasticity for demand buyback programs.

Development of Cost Estimates

Demand response strategies vary significantly with respect to both type and level of costs. Applicable resource acquisition costs for DR generally fall into two categories: 1) fixed direct expenses such as infrastructure, administration, and data acquisition; and 2) variable costs (i.e., incentive payments to participants). For this project, cost estimates are based on the experiences of PacifiCorp and other utilities, as well as RTOs offering various DR programs.

Fixed Costs. Fixed costs vary significantly across various DR resource acquisition programs and depend, to a large extent, on program design. For example, implementation of some market-based programs, such as demand buyback, may require up-front investments in communication and data acquisition infrastructures, while tariff-based programs may be implemented at a relatively low cost to the utility.

Variable Costs. Estimation and treatment of variable costs, particularly in the case of market-based programs poses a much greater challenge in determining the price component of the supply curve as, clearly, these will have a direct effect on the quantity of resources that are available. As described above, elasticity estimates were used to account for these impacts.

Table 12 outlines the development (up-front investment) and annual costs for the three categories of cost inputs: per-kW/year, per-customer, and program administration. Incentive payments for large commercial and industrial customers are often paid on a per-kW basis. On a per-customer basis, development costs typically include control hardware, installation, and marketing costs; annual costs include maintenance and incentives. Program costs were assumed to be relatively consistent across all programs - $300,000 to begin a new program, $150,000 to expand existing programs[10]; $100,000 in ongoing administrative cost.[11]

Table 12: Cost Inputs

Cost Type/ Frequency	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
per kW-year								
Development	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Annual	- - -	- - -	$48	$10	$105	$48	- - -	$10
per Customer-year (including meter costs)								
Development	$320	$320	$1,200	$700	- - -	$1,200	$500	$700
Annual	$112	$55	- - -	$1,000	- - -	- - -	$50	- - -
Program								
Development	$300,000	$150,000	$300,000	$150,000	$300,000	$300,000	$300,000	$150,000
Annual	$100,000	$100,000	$100,000	$600,000	$100,000	$100,000	$100,000	$100,000

These costs are allocated to each year of the planning horizon, based on:

$$Costs_{sy} = \$Pgm_{dy1} + \$Pgm_{a} + (\$kW_{a} \times kW_{y}) + (\$Customer_{d} \times Part_{y-y0}) + (\$Customer_{a} \times Part_{y})$$

Where,

---

10 PacifiCorp Energy Exchange (2001) spent over $200,000 in initial costs. TOU (2001) had initial costs of $341,000, including load research.

11 Energy Exchange (2005) spends $72,000 annually in external vendor costs (not including PacifiCorp administrative costs), Idaho Irrigation Pilot (2005) spent $55,000 in program management, TOU had ongoing costs of $155,000 (2002) and $110,000 (2003).

- $Costs_{sy}$ are the costs for a program strategy *s* in year *y*,
- $\$Pgm_{dy1}$ are the program development costs in year 1 only
- $\$Pgm_{a}$ are the annual program costs
- $\$kWa$ are the annual costs on a per kW basis (Table 12)
- kW_y is the amount of kW potential in year *y*. This study uses a three-year ramping, such that one-third of the achievable potential, shown in Table 4, is added in each of the first three program years. The quantity in subsequent years increases at the same rate as sales.
- $\$Customer_d$ are per-customer development costs
- $Part_{y-y0}$ is the number of new participants in the program in year y
- $\$Customer_a$ is the annual cost per customer
- $Part_y$ is the number of total participants in the program, as a function of PartkW, which is the kW impact per customer, as shown in Table 13 (program-level assumptions found in Section V).

$$Part_y = \frac{kW_y}{Part_{kW}}$$

Table 13: Load Impact per Customer (kW)

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	2.0	1.5	- - -	- - -	- - -	- - -	2	- - -
Education	- - -	- - -	124	- - -	- - -	124	21	124
Food Stores	- - -	- - -	134	- - -	- - -	134	22	134
Hospitals	- - -	- - -	- - -	- - -	- - -	- - -	-	- - -
Hotels/Motels	- - -	2.0	104	- - -	- - -	104	10	104
Other Health	- - -	2.0	82	- - -	- - -	82	- - -	82
Miscellaneous	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Offices	- - -	2.0	221	- - -	- - -	221	7	221
Assembly	- - -	2.0	230	- - -	- - -	230	- - -	230
Restaurants	- - -	2.0	- - -	- - -	- - -	- - -	- - -	- - -
Retail	- - -	2.0	- - -	- - -	- - -	- - -	- - -	- - -
Warehouses	- - -	2.0	173	- - -	- - -	173	- - -	173
Industrial	- - -	- - -	531	- - -	- - -	531	53	531
Irrigation	- - -	- - -	- - -	90	- - -	- - -	- - -	- - -

Resource Interaction Estimates

The final step in supply curve development is to estimate the amount of market potential that is available for each program in the portfolio. Table 14 outlines the percent of market potential that is considered available, given the ranking of programs by levelized cost with consideration given to reliability. For example, 100% of demand buyback and scheduled firm irrigation is considered achievable. Although critical peak pricing is ranked next in levelized cost, it is another non-firm resource, so it becomes tertiary to curtailable rates. Curtailable rates and dispatchable large C&I compete for the same target market as DBB, therefore only 50% of their market potential will be available. The summer DLC program is the least expensive residential and small commercial control program. Therefore 100% of this program is available. Since the TES also targets the cooling loads (cool storage) as a secondary option, half of the TES potentials are assumed to be available.

Table 14: Interaction (Percent of Market Potential Available)

Program Name/Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Residential	50%	100%	- - -	- - -	- - -	- - -	20%	- - -
Education	- - -	- - -	50%	- - -	- - -	50%	20%	100%
Food Stores	- - -	- - -	50%	- - -	- - -	50%	20%	100%
Hospitals	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Hotels/Motels	- - -	100%	50%	- - -	50%	50%	20%	100%
Other Health	- - -	100%	50%	- - -	50%	50%	- - -	100%
Miscellaneous	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -
Offices	- - -	100%	50%	- - -	50%	50%	20%	100%
Assembly	- - -	100%	50%	- - -	50%	50%	- - -	100%
Restaurants	- - -	100%	- - -	- - -	50%	- - -	- - -	- - -
Retail	- - -	100%	- - -	- - -	50%	- - -	- - -	- - -
Warehouses	- - -	100%	50%	- - -	50%	50%	- - -	100%
Industrial	- - -	- - -	50%	- - -	- - -	50%	20%	100%
Irrigation	- - -	- - -	50%	100%	- - -	50%	- - -	- - -

V. Detailed Program Assumptions

Table 15. Fully Dispatchable – Winter

Programs Researched	Portland General Electric Space and Water Heating Direct Load Control Program; Pennsylvania, New Jersey, Maryland ISO water heating; Florida Power & Light Residential On Call program; Puget Sound Energy Home Comfort Control Thermostat; Hawaiian Electric Residential Hot Water; Wisconsin Public Services DLC
Load Basis	Average of top 87 winter hours
Basis for Cost Calculations	Development: Customer - $300 for control equipment and labor, $200 for meter and installation labor (PGE – Quantec 2003) but installed for only 10% of participants, $300,000 for program development; Annual: $30 in maintenance, $9 (1.5/month for 6 months) in communications, $72 ($12/month for 6 months - both water heating and space) in incentives, and $100,000 annual program administration.
High/Low Cost Notes	High assumes incentives are increased ($15/month - $90), low is half incentive ($6/mth - $36). Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Less than complete technical ability to cycle different technologies (90%) and 50% cycling strategy; therefore 45%
Eligible Load (%)	Residential space heating and water heating
Program Participation (%)	High is based on 20% participation of FPL On Call program, base (10%) closer to Duke program of 13% (Duke – Quantec 2005), and low (5%) represents low program participation (DOE - 2006)
Event Participation (%)	100%
Current Program (kW)	NA
Per-Customer Impacts (kW)	2kW estimate per participant based (PSE, Quantec 2003) - includes cycling strategy
Hours Per Month	3 hours in January; 84 hours in December (based on the distribution of the PacifiCorp 2005 system profile)

Table 16. Fully Dispatchable – Summer

Programs Researched	Florida Power & Light Residential On Call & Business On Call; SCE Large Business Summer Discount Plan; Wisconsin Public Services; Duke Residential AC Program, PacifiCorp and MidAmerican
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Customer - $300 for control equipment and labor, $200 for meter and installation labor (PGE – Quantec 2003) but installed for only 10% of participants, $300,000 for program development; Annual: $30 in maintenance, $4.5 (1.5/month for 3 months) in communications, incentives - $20 (3 months at $7/month - PSE pays $6, Duke $8, PAC $7), and $100,000 annual program administration
High/Low Cost Notes	High assumes incentives are doubled ($40), low is half incentive ($10). Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Less than complete technical ability to cycle different technologies (90%) and 50% cycling strategy; therefore 45%
Eligible Load (%)	Cooling load for residential and portion of commercial load that is less than 30 kW (PacifiCorp - Quantec 2003)
Program Participation (%)	Assumes 20% residential and 5% small commercial (FP&L - 13% small C&I participation, 19% residential, PAC Utah Cool Keeper 27% residential and ~0% commercial), high assumes that 5% more program participation is possible, low assumes 5% less
Event Participation (%)	100%
Current Program (kW)	65 MW of load reduction in Utah Cool Keeper Program on Dispatch mode
Per-Customer Impacts (kW)	Impact: Cooling - 1.5 kW for residential, 2.0 kW for small com, DOE 2006, Quantec 2003
Hours Per Month	June 8, July 54; August 32 – adjusts 2005 System load to account for experience in program dispatch by Cool Keeper

Table 17. Fully Dispatchable – Large C&I

Programs Researched	Florida Light & Power C&I On Call; Hawaiian Electric Large Commercial; Wisconsin Public Services DLC; Southern California Edison Large Business Summer Discount Plan
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Per customer of $500 for targeted marketing and $700 for meter (Duke – Quantec 2005); $300,000 for program development, $100,000 annual program administration. Per kW costs assume $8/month for 3 months (double the incentive as curtailable rates but for fewer months)
High/Low Cost Notes	High incentive is $14/month and low is $6/month (again, double curtailable rates incentive; see curtailable rates for references) Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of cooling load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003) and assuming only 38% with EMS systems (CBSA 05)
Program Participation (%)	Participation - Florida Power And Light C&I On Call has less than 1% of all customers. Because our figures already account for those not eligible, we have assumed 3% base, 8% high, and 1% low.
Event Participation (%)	90%
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	June 8, July 54; August 32 - adjusts 2005 System load to account for experience in program dispatch by Cool Keeper, assuming that system decisions to curtail residential customers would be similar for C&I customers

Table 18. Scheduled Firm – Irrigation

Programs Researched	BPA Irrigation, Idaho Power, PacifiCorp
Load Basis	Average of entire summer on-peak period
Basis for Cost Calculations	Development: $700 installed cost of advanced metering technologies; Idaho IRR: Annual: $10 per kW ($8.5 in 2005), $300,000 for program development, $100,000 annual program administration. Also includes $500K of additional expenditures committed in 2005 for ongoing programs by PacifiCorp.
High/Low Cost Notes	High cost doubles incentive; low assumes the same, Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Less than complete technical ability to schedule reductions on all load (e.g., lift stations)
Eligible Load (%)	Irrigation sector
Program Participation (%)	Program participation of 50% (2005 Idaho IRR - 100 MW signed up of 200 MW load) is assumed to be base. High and low has relatively tight band +/-5%.
Event Participation (%)	50% event participation assumes participants sign up only for 2 out of 4 days (similar to PacifiCorp Idaho program)
Current Program (kW)	48 MW from Idaho program
Per-Customer Impacts (kW)	Idaho reduction of 100 kW per customer reduced to 90 to account for smaller irrigators in other regions
Interaction	100% taken due to relatively inexpensive cost and lack of competition with other programs.
Variable Cost $/MWh	NA
Hours Per Month	June – August 96 hours per month, September 48 hours per month (4 days per week, 6 hours per day)

Table 19. Thermal Energy Storage

Programs Researched	Based on RFP response to PacifiCorp, summarized for Quantec in "TES Overview"
Load Basis	Average of entire summer on-peak period
Basis for Cost Calculations	Costs from "TES Overview" sent to Quantec on June 2, 2006 using per-kW costs by external vendor, $300,000 for program development, $100,000 annual program administration
High/Low Cost Notes	Incentives remain constant, Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Less than complete technical ability to use this technology (90%) on cooling load
Eligible Load (%)	Using portion of commercial cooling load that is less than 30 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	20% program participation, with +/- 5% for high and low participation
Event Participation (%)	100%
Current Program (kW)	NA
Per-Customer Impacts (kW)	NA
Hours Per Month	240 – April, 186 – May, 180 – June, 186 – July, 186 – August, 180 – September, 279 October

Table 20. Curtailable Rates

Programs Researched	Duke Interruptible Power Service; Georgia Power (Southern) Demand Plus Energy Credit; Duke Curtailable Service Pilot; Dominion Virginia Power Curtailable Service; MidAmerican; ConEd Interruptible/Curtailment Service, Southern California Edison C&I Base Interruptible Program, Wisconsin
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Per Customer of $500 for marketing and $700 for meter (Duke - Quantec, 05); $300,000 for new program development, $100,000 annual program administration, Base incentive of $48 ($4/kWMonth) (Pacific Gas and Electric pays $3-$7/kWMonth, Southern California Edison pays $7/kWMonth, Wisconsin Power and Light pays $3.3/kWMonth, MidAmerican pays $3.3, Duke Power pays $3.5/kW-Month).
High/Low Cost Notes	Base incentive of $48 ($4/kWMonth) is increased by 50% in high case. Low assumes same incentive as base ($42). Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	National participation ranges from slightly greater than 0% (ISO NE) of customers to 30%, (NYISO 29%, Duke 14%). Base assumes 25% (due to load eligibility already accounted for), 5% more for high case and 12.5% less for low case.
Event Participation (%)	Event Participation reflects compliance rate (Duke - 90% + compliance, CEC – 90% + compliance Goldman (2002))
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 69; August 18 (based on the distribution of the PacifiCorp 2005 system profile)

Table 21. Critical Peak Pricing

Programs Researched	Gulf Power GoodCents Select; Pacific Gas and Electric Critical Peak Pricing; Southern California Edison Critical Peak Pricing; San Diego Gas and Electric Critical Peak Pricing
Load Basis	Average of top 87 summer hours
Basis for Cost Calculations	Development: Customer: $500 for advanced metering technologies; Program - $300,000 for new program development; Annual: Customer - $20 for meter reading, extra mailing, and messaging (PSE – Quantec (2004)), $30 to account for the rate and energy benefits to the customer (Quantec PacifiCorp TOU (2005)) $100,000 annual program administration
High/Low Cost Notes	Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Range of impacts from high 41% (Gulf Power super peak) to 18% (Piette, 2006), therefore assume low-mid-point of 25%, (other relevant references – McAulife (2004) DOE 2006)
Eligible Load (%)	Eligibility- all customers assumed to be eligible except those deemed unable to respond (based on sectors reported in Quantum (2004))
Program Participation (%)	Current programs in nation have very low participation (reviewed seven programs McAulife (2004) and Gulf Power with maximum of 3% - PG&E commercial program) - base is 3%, low is 0.5% and high is 5.5%
Event Participation (%)	Event participation assumed to be less than all - i.e., 90%
Current Program (kW)	NA
Per-Customer Impacts (kW)	Per customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 69; August 18 (based on the distribution of the PacifiCorp 2005 system profile)

Table 22. Demand Buyback

Programs Researched	Pacific Gas and Electric Demand Buyback (Commercial and Industrial); Southern California Edison Demand Buyback (Commercial and Industrial); San Diego Gas and Electric Demand Buyback; New York ISO Day Ahead Demand Response, PacifiCorp
Load Basis	Average of top 175 summer hours
Basis for Cost Calculations	Development: $700 for advanced meter; Program development cost of $150,000 for expansion; $100,000 annually for program administration. Incentive of $10/kW is consistent with 2005 PacifiCorp Integrated Resource Plan base prices of $60/MWh
High/Low Cost Notes	High and low incentive levels are consistent with 2005 PacifiCorp Integrated Resource Plan base prices of $40/MWh (low) and $100/MWh (high). Annual program administrative costs are increased by $50,000 in high case and reduced by $50,000 in low case.
Technical Potential	Total curtailable load based on Goldman (2004)- National Trends, by sector. If not mentioned, unclassified was used.
Eligible Load (%)	Using portion of load that is greater than 250 kW as eligible (PacifiCorp - Quantec 2003)
Program Participation (%)	Range of program participation is from 0-6% (various California utilities – Quantum (2004)) to 17-25% (PJM/NYISO – Goldman (2004)). This study uses 35% to account for the eligibility correction for those >250 kW. High is 30%, low is 5%
Event Participation (%)	Event participation calculated from 2001 Northwest demand bidding experience
Current Program (kW)	1 MW of participation (165 MWh over 15 events, 10 hours per event)
Per-Customer Impacts (kW)	Per-customer impacts are calculated as product of average load for customers >250 kW and the technical potential above
Hours Per Month	July 129; August 46 (based on the distribution of the PacifiCorp 2005 system profile)

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Appendix A: East Region Results

Table 23: Technical Potential (MW), East

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	143	- - -	- - -	377	392	368
Commercial	- - -	35	30	- - -	59	79	134	76
Irrigation	- - -	- - -	- - -	254	- - -	- - -	- - -	- - -
Residential	163	318	- - -	- - -	- - -	- - -	342	- - -
Total	***163***	***353***	***173***	***254***	***59***	***455***	***868***	***444***
% of East Peak	*3%*	*7%*	*3%*	*5%*	*1%*	*9%*	*17%*	*9%*

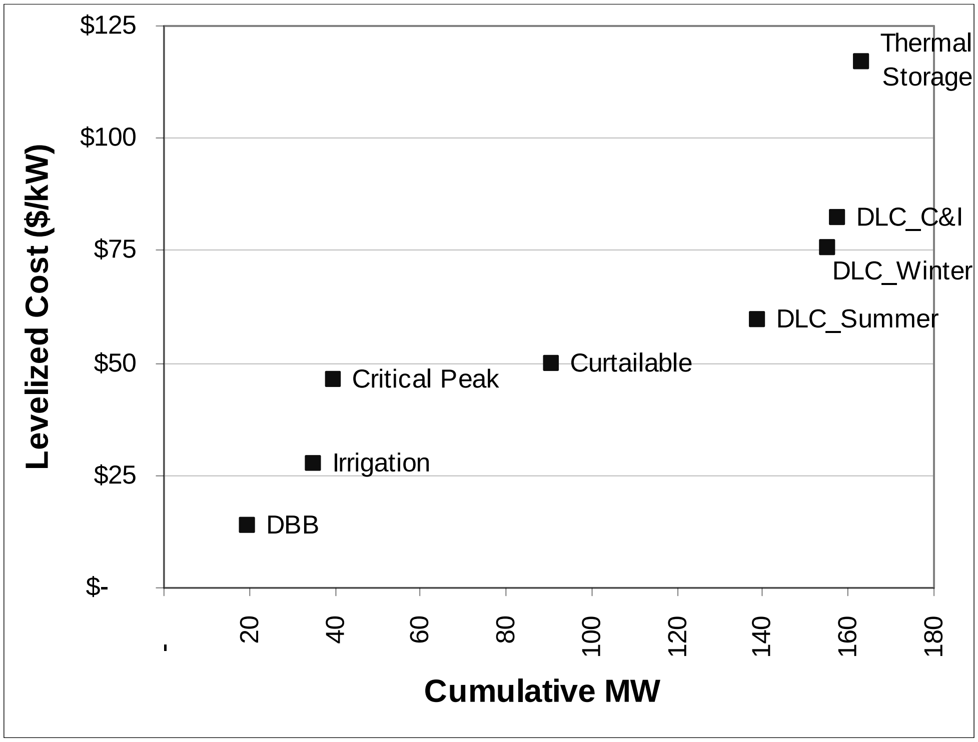
Table 24: Market Potential (MW), East

Sector	Fully Dispatchable			Scheduled Firm – Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	4	- - -	- - -	85	11	16
Commercial	- - -	2	1	- - -	12	18	4	3
Irrigation	- - -	- - -	- - -	63	- - -	- - -	- - -	- - -
Residential	33	111	- - -	- - -	- - -	- - -	9	- - -
Total	***33***	***113***	***5***	***63***	***12***	***102***	***23***	***19***
% of East Peak	*0.7%*	*2.3%*	*0.1%*	*1.3%*	*0.2%*	*2.0%*	*0.5%*	*0.4%*

Table 25. Achievable Potential (MW) and Costs, East

	Fully Dispatchable			Scheduled Firm – Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Resource Costs ($/kW/yr)	$76	$59	$82	$28	$117	$50	$46	$14	- - -
Achievable Potential	**16**	**113**	**2**	**63**	**6**	**51**	**5**	**19**	**276**
Potential Net of Current Programs	16	48	2	15	6	51	5	19	**163**

Figure 12: Cumulative Supply Curve, East



Appendix B: West Region Results

Table 26. Technical Potential, West

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	50	- - -	- - -	133	138	132
Commercial	- - -	20	21	- - -	35	54	98	54
Irrigation	- - -	- - -	- - -	128	- - -	- - -	- - -	- - -
Residential	210	33	- - -	- - -	- - -	- - -	275	- - -
Total	***210***	***54***	***71***	***128***	***35***	***187***	***512***	***185***
% of West Peak	*7%*	*2%*	*2%*	*4%*	*1%*	*6%*	*16%*	*6%*

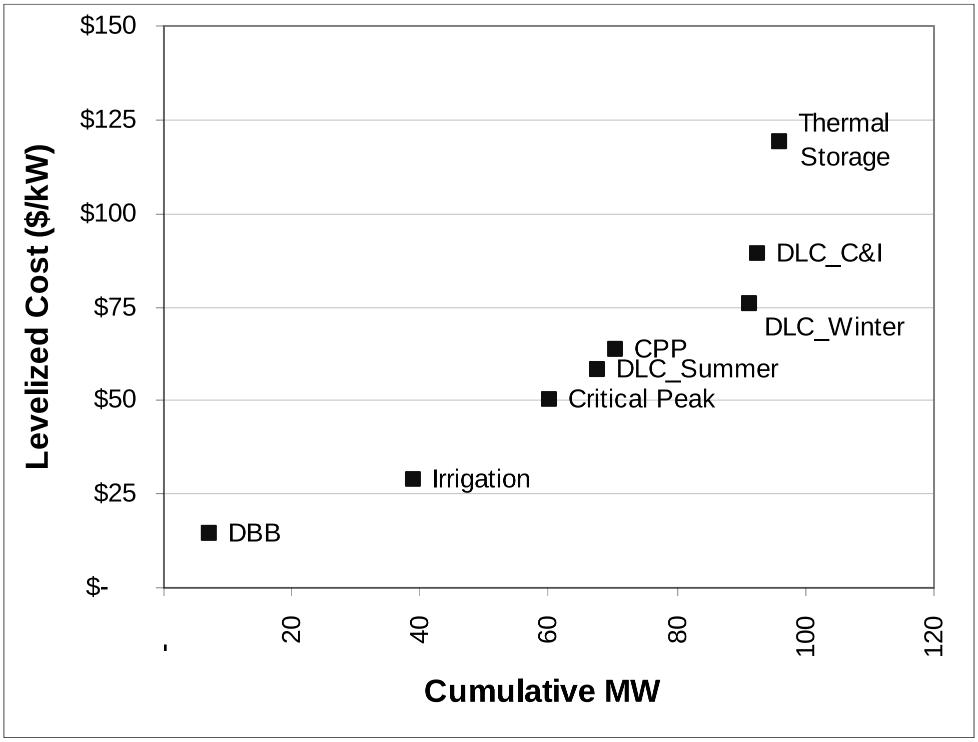
Table 27. Market Potential, West

Sector	Fully Dispatchable			Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
	Winter	Summer	Large C&I					
Industrial	- - -	- - -	1	- - -	- - -	30	4	6
Commercial	- - -	1	1	- - -	7	12	3	2
Irrigation	- - -	- - -	- - -	32	- - -	- - -	- - -	- - -
Residential	42	7	- - -	- - -	- - -	- - -	7	- - -
Total	**42**	**8**	**2**	**32**	**7**	**42**	**14**	**8**
% of West Peak	*1.3%*	*0.2%*	*0.1%*	*1.0%*	*0.2%*	*1.3%*	*0.4%*	*0.3%*

Table 28. Achievable Potential (MW) and Costs, West

	Fully Dispatchable			Scheduled Firm – Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback	Total
	Winter	Summer	Large C&I						
Resource Costs ($/kW/yr)	$76	$58	$89	$29	$119	$50	$63	$15	- - -
Achievable Potential	**21**	**8**	**1**	**32**	**3**	**21**	**3**	**8**	97
Potential Net of Current Programs	21	8	1	32	3	21	3	7	96

Figure 13: Supply Curve, West



Appendix C: Data Provided to IRP

Figure 14: East Region, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	51	5	19
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 76	$ 59	$ 82	$ 28	$ 117	$ 50	$ 46	$ 14
Low								
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	22	1	6
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 58	$ 53	$ 159	$ 29	$ 115	$ 38	$ 95	$ 13
High								
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	63	9	46
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 84	$ 73	$ 101	$ 37	$ 118	$ 86	$ 42	$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 15: West Region, Reference Case

Program Name	Fully Dispatchable-Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	21	3	8
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 76	$ 58	$ 89	$ 29	$ 119	$ 50	$ 63	$ 15
Low								
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	9	0	3
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 58	$ 61	$ 185	$ 30	$ 116	$ 39	$ 144	$ 14
High								
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	26	5	19
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 84	$ 70	$ 104	$ 37	$ 121	$ 87	$ 56	$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 16: System, Reference Case

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	72	7	28
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 76	$ 59	$ 84	$ 28	$ 118	$ 50	$ 49	$ 14
Low								
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	30	1	9
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 58	$ 53	$ 167	$ 29	$ 115	$ 39	$ 91	$ 13
High								
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	88	14	65
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 84	$ 72	$ 102	$ 37	$ 119	$ 86	$ 45	$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 17: East Region, No DBB

Program Name	Fully Dispatchable-Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	102	5
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 76	$ 59	$ 82	$ 28	$ 117	$ 49	$ 46
Low							
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	43	1
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 58	$ 53	$ 159	$ 29	$ 115	$ 37	$ 95
High							
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	125	9
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 84	$ 73	$ 101	$ 37	$ 118	$ 85	$ 42
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 18: West Region, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	42	3
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs ($/kW/yr)	$ 76	$ 58	$ 89	$ 29	$ 119	$ 49	$ 63
Low							
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	18	0
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs ($/kW/yr)	$ 58	$ 61	$ 185	$ 30	$ 116	$ 38	$ 144
High							
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	51	5
Currently Under Contract	-	-	-	-	-	-	-
Resource Costs ($/kW/yr)	$ 84	$ 70	$ 104	$ 37	$ 121	$ 86	$ 56
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 19: System, No DBB

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Reduction Period (Hours)	2	2	4	6	6	4	4
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base							
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	144	7
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 76	$ 59	$ 84	$ 28	$ 118	$ 49	$ 49
Low							
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	61	1
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 58	$ 53	$ 167	$ 29	$ 115	$ 37	$ 91
High							
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	177	14
Currently Under Contract	-	65	-	48	-	-	-
Resource Costs ($/kW/yr)	$ 84	$ 72	$ 102	$ 37	$ 119	$ 85	$ 45
Hours Available by Month							
January	3	-	-	-	-	-	-
February	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-
May	-	-	-	-	186	-	-
June	-	8	8	96	180	-	-
July	-	46	46	96	186	69	69
August	-	33	33	96	186	18	18
September	-	-	-	48	180	-	-
October	-	-	-	-	279	-	-
November	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-

Figure 20: East Region, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	16	113	2	63	6	51	5	19
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 75	$ 58	$ 82	$ 27	$ 117	$ 50	$ 40	$ 14
Low								
Total Achievable Potential --Maximum (MW)	8	78	0	51	4	22	1	6
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 57	$ 52	$ 159	$ 28	$ 115	$ 38	$ 89	$ 13
High								
Total Achievable Potential --Maximum (MW)	25	131	7	76	7	63	9	46
Currently Under Contract	-	65	-	48	-	-	-	-
Resource Costs ($/kW/yr)	$ 83	$ 71	$ 101	$ 36	$ 118	$ 86	$ 36	$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 21: West Region, No Metering

Program Name	Fully Dispatchable-Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	21	8	1	32	3	21	3	8
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 75	$ 57	$ 89	$ 28	$ 119	$ 50	$ 56	$ 14
Low								
Total Achievable Potential --Maximum (MW)	11	2	0	26	3	9	0	3
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 57	$ 60	$ 185	$ 29	$ 116	$ 39	$ 136	$ 14
High								
Total Achievable Potential --Maximum (MW)	32	10	3	38	4	26	5	19
Currently Under Contract	-	-	-	-	-	-	-	1
Resource Costs ($/kW/yr)	$ 83	$ 69	$ 104	$ 37	$ 121	$ 86	$ 48	$ 19
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-

Figure 22: System, No Metering

Program Name	Fully Dispatchable- Winter	Fully Dispatchable - Summer	Fully Dispatchable - Large C&I	Scheduled Firm - Irrigation	Thermal Energy Storage	Curtailable Rates	Critical Peak Pricing	Demand Buyback
Variable Costs ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Market Prices
Demand Reduction Period (Hours)	2	2	4	6	6	4	4	10
Start Year	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009
Base								
Total Achievable Potential --Maximum (MW)	37	120	3	95	9	72	7	28
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 75	$ 58	$ 84	$ 27	$ 118	$ 50	$ 42	$ 14
Low								
Total Achievable Potential --Maximum (MW)	19	80	1	76	7	30	1	9
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 57	$ 52	$ 167	$ 29	$ 115	$ 38	$ 84	$ 13
High								
Total Achievable Potential --Maximum (MW)	56	141	9	114	12	88	14	65
Currently Under Contract	-	65	-	48	-	-	-	1
Resource Costs ($/kW/yr)	$ 83	$ 71	$ 102	$ 36	$ 119	$ 86	$ 38	$ 18
Hours Available by Month								
January	3	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	240	-	-	-
May	-	-	-	-	186	-	-	-
June	-	8	8	96	180	-	-	-
July	-	46	46	96	186	69	69	129
August	-	33	33	96	186	18	18	46
September	-	-	-	48	180	-	-	-
October	-	-	-	-	279	-	-	-
November	-	-	-	-	-	-	-	-
December	84	-	-	-	-	-	-	-