PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 31, 2010

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

Re: Docket No. LC 47
PacifiCorp's 2008 Integrated Resource Plan Update

Please find enclosed an original and five (5) copies of PacifiCorp's 2008 Integrated Resource Plan ("IRP") Update ("2008 IRP Update"). Copies of the report are available electronically and will be posted on PacifiCorp's website, at www.pacificorp.com. The Company's 2008 IRP was filed with the Public Utility Commission of Oregon ("Commission") on May 29, 2009.

The 2008 IRP Update is being submitted for informational purposes only. Since the Company expects to file its next IRP no later than March 31, 2011, it does not request acknowledgement of its 2008 IRP Update. No action is required by the Commission.

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

By E-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
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If there are informal inquiries concerning the filing please contact Pete Warnken, Manager, Integrated Resource Planning at (503) 813-5518 or Joelle Steward, Regulatory Manager, at (503) 813-5542.

Sincerely,

Andrea Kelly

Andrea L. Kelly
Vice President, Regulation

cc: Service List LC 47 (w/out enclosures)

CERTIFICATE OF SERVICE

I certify that I have cause to be served the foregoing **PacifiCorp's 2008 Integrated Resource Plan Update** in OPUC Docket No. LC 47 by electronic mail and US mail to those parties who have not waived paper service on the attached service list. DATED this 31st day of March, 2010.

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Let's turn the answers on.

2008 Update
Integrated Resource Plan

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

March 31, 2010

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

This 2008 Integrated Resource Plan Update (2008 IRP Update) 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 updated IRP action plan will be submitted to the State Commissions for informational purposes or as required by their respective IRP preparation and filing rules.

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Cover Photos (Left to Right):
Wind: Foote Creek 1
Hydroelectric Generation: Yale Reservoir (Washington)
Demand side management: Agricultural Irrigation
Thermal-Gas: Currant Creek Power Plant
Transmission: South Central Wyoming line

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EXECUTIVE SUMMARY

This 2008 Integrated Resource Plan (IRP) update report describes resource planning activities that occurred subsequent to the filing of the 2008 Integrated Resource Plan in May 2009, and presents the Company's revised 10-year resource portfolio and IRP action plan.[1] These activities centered on preparation of the Company's 10-year business plan for the period 2010-2019 ("2010 business plan").

Preparation of the 2010 business plan occurred against the back-drop of the economic recession and lower load growth; a tight credit market; the continuing need for large capital expenditures to support load growth, system reliability, emission controls and other regulatory mandates; and ongoing uncertainty regarding government policies on climate change and clean energy. As a consequence, PacifiCorp reexamined the need and timing for capital investments and, where appropriate and feasible, the business plan eliminates or defers resource investments.

Against this backdrop, allocating capital for transmission expansion is a precondition for maintaining transmission system reliability, supporting future load obligations, and accessing new and existing resource areas. PacifiCorp also assumed that making investments in environmental controls for sulfur oxides (SO_X) and nitrous oxides (NO_X) was needed unless the emission control requirements are modified.

Another key business planning consideration is the progress and challenges associated with the Energy Gateway transmission expansion project. Construction of the first segment (Populus to Terminal) is underway and remains on schedule for completion in 2010. In an effort to maintain schedule flexibility for future segments, in-service dates have been updated to provide flexibility while maintaining the urgency to complete the project. These date adjustments, combined with the lack of additional transmission capacity on the existing system, prompted deferral of planned wind resources dependent on the availability of new transmission. PacifiCorp will continue its focus on maintaining system reliability and efficient use of new and existing transmission as additional operational experience is gained with large-scale and rapid wind penetration in certain areas of the system.

As an extension of ongoing transmission planning efforts, Idaho Power and PacifiCorp also recently signed a Memorandum of Understanding ("MOU") that outlines a process to fully define and develop joint ownership of extensive transmission facilities,

[1] Action plan revisions reflect modified resource strategies reflecting the current planning environment, as well as revised or new action items adopted by the Company as part of the 2008 IRP acknowledgment proceedings.

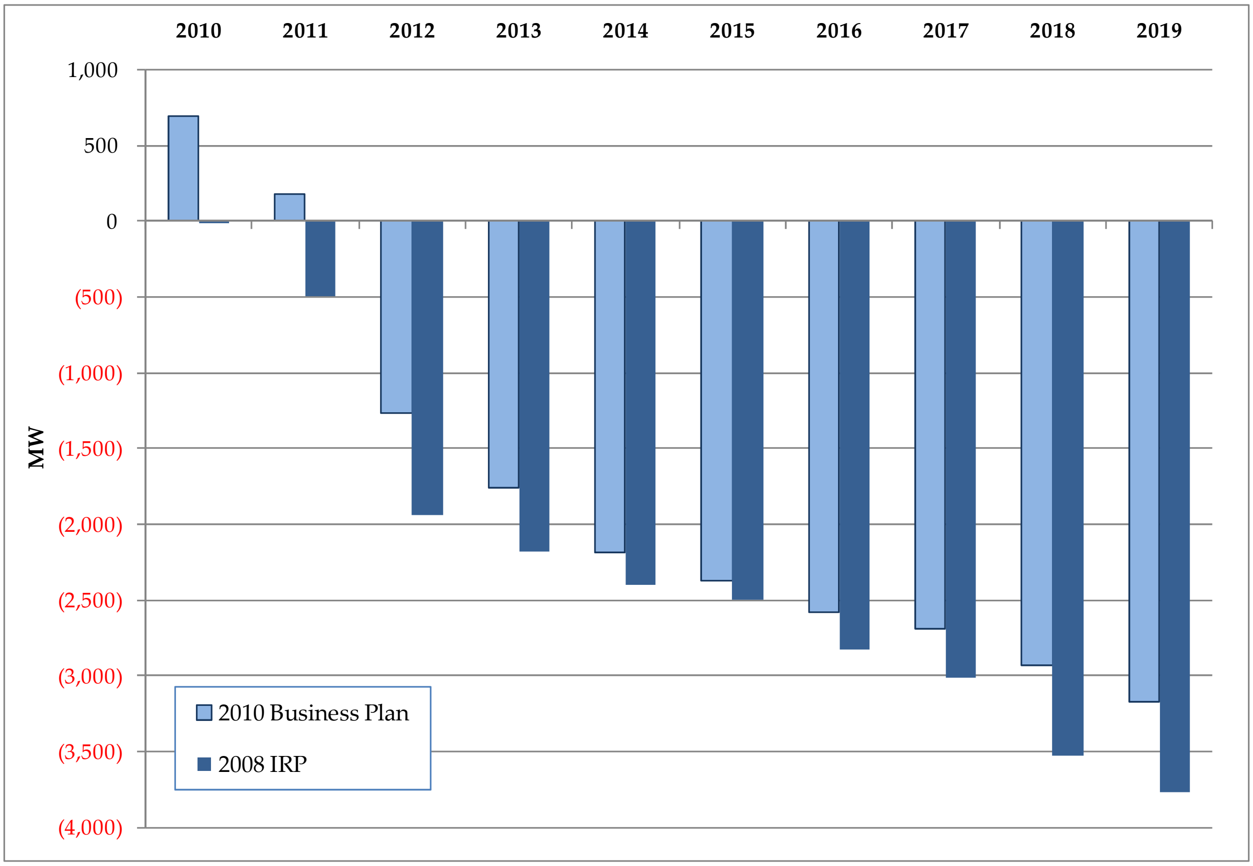
including the Boardman to Hemingway transmission project and the Gateway West Project. The two companies already share a partnership on Gateway West. Joint ownership of the Hemingway to Boardman project is a new development and is expected to replace further near-term review and consideration of the Hemingway to Captain Jack project listed as “under review” in the 2008 IRP.

At least two factors could change the Company’s decision to defer additional renewable energy resources until 2017. First, as the particulars regarding federal emissions reduction regulations become clearer, it may be prudent to resume adding renewable energy sooner than 2017. Second, the Company remains open to acquiring renewable energy projects that represent economically attractive and unique opportunities for its customers. This aspect of the updated IRP action plan remains unchanged.

With the 2010 business plan load forecast prepared in October 2009 (showing reductions in annual system loads from 2.2 million megawatt-hours in 2010 to 0.6 million megawatt-hours by 2019 relative to the 2008 IRP load forecast prepared in February 2009), the system becomes short on capacity in 2012 rather than 2011 without additional resources (Figure ES.1)

Development of the 2010 business plan resource portfolio was supported by the use of the Company’s capacity expansion optimization model, *System Optimizer*, which helped determine the timing and type of gas resources and firm market purchases based on updates to forecasted loads, resources, market prices, and other model inputs.

Figure ES.1 – Capacity Position Comparison, 2008 IRP versus the 2010 Business Plan



The significant resource changes with respect to the 2008 IRP preferred portfolio include the following:

- Deferral of the need for new natural gas resources from 2014 and 2016 to 2015 and 2018
- Postponement of wind resource acquisition in the 2012-2016 timeframe
  - This deferral does not impact the Company's ability to satisfy state and potential federal renewable portfolio standard requirements throughout this period.
  - PacifiCorp has exceeded the MidAmerican Energy Holdings Company commitment to have 1,400 MW of economic renewable resources in the portfolio by 2015; with resources acquired after 2003, PacifiCorp is expected to surpass this commitment by 333 MW by the end of 2010.

- A 170 MW reduction in the 200 MW planned expansion of the Utah Cool Keeper residential air conditioning control program from 2010 through 2019[2], which has been generally offset by the proposed introduction of a Commercial Curtailment product and increased participation forecasts for the Company's irrigation load control programs.

Table ES.1 summarizes the 2010 business plan portfolio resources, showing the years for which the resources are available to meet summer peak loads.

Table ES.1 – 2010 Business Plan Portfolio

		Capacity, MW											Cumulative
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total (2010-19)**
East													
	CCCT F 2x1, Utah (North 2015, South 2018)	-	-	-	-	-	-	607	-	-	536	-	**1,143**
	East PPA	-	-	-	200	-	-	-	-	-	-	-	**200**
	Coal & Gas Capacity Upgrades	2	16	20		2		11	37	-	-	-	**86**
	Wind *	128	227	200	-	-	-	-	-	160	100	200	**887**
	DSM, Class 1, Utah Cool Keeper Load Control	-	18	6	5	-	-	-	-	-	-	-	**28**
	DSM, Class 1, Other **	-	25	5	15	20	10	3	-	-	-	-	**78**
	DSM Class 2	56	65	65	66	68	68	49	50	51	50	53	**585**
	Front Office Transaction - 3Qtr HLH	75	-	-	200	338	519	300	300	350	347	350	
West													
	Coal Plant Turbine Upgrades	-	4	-	-	-			12	12	8	12	**48**
	Wind	75	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Other **	-	-	5	17	18	5	-	-	-	-	-	**45**
	DSM Class 2	39	40	40	39	40	40	37	37	27	27	27	**353**
	Solar Photovoltaic (utility-scale)	-	-	1.8	1.8	1.8	1.8	1.8	-	-	-	-	**8.8**
	Front Office Transaction-3Qtr HLH	-	-	-	404	594	704	494	623	608	289	444	
	Annual Additions, Long Term Resources	**299**	**394**	**342**	**344**	**149**	**125**	**708**	**136**	**251**	**721**	**292**	
	Annual Additions, Short Term Resources	**75**	-	-	**604**	**932**	**1,223**	**794**	**923**	**958**	**636**	**794**	
	Total Annual Additions	**374**	**394**	**342**	**948**	**1,081**	**1,348**	**1,503**	**1,059**	**1,208**	**1,357**	**1,087**	

* The 2011 wind resource is the Top of the World project (200 MW), with an in-service date of December 31, 2010.

* *Other Class 1 DSM consists of (1) irrigation and residential air conditioning control, and (2) commercial curtailment, including customer-owned standby generation.

Table ES.2 presents the updated 2008 IRP Action Plan. The Action Plan table in Chapter 6 indicates changes to the version published in the 2008 IRP.

[2] The Utah legislature passed a bill in March 2010 that allows Cool Keeper to be designed as an opt-out program. PacifiCorp will revisit the program's growth assumptions for the next business plan and IRP as a result.

Table ES.2 – IRP Action Plan Update

Action items anticipated to extend beyond the next two years, or occur after the next two years, are indicated in italics.

Action Item	Category	Timing	Action(s)
1	**Renewables**	**2010 - 2019**	Acquire an incremental 890 MW of renewable resource by 2019. Successfully add 230 MW of wind resources in 2010 and 200 MW of wind resources in 2011 that are currently committed to. • *Procure up to an additional 460 MW of cost-effective wind resources for commercial operation, subject to transmission availability, in the 2017 to 2019 time frame via RFPs or other opportunities.* • *Monitor geothermal, solar and emerging technologies, and government financial incentives; procure geothermal, solar or other cost-effective renewable resources during the 10-year investment horizon.* • *Continue to evaluate the prospects and impacts of Renewable Portfolio Standard rules and CO_2 emission regulations at the state and federal levels, and adjust the renewable acquisition timeline accordingly.*
2	**Firm Market Purchases**	**2010 - 2019**	Implement a bridging strategy to support acquisition deferral of long-term intermediate/base-load resource(s) in the east control area until the beginning of summer 2015, unless cost-effective long-term resources such as renewables or thermal plant assets are available and their acquisition is in the best interests of customers. • Acquire the following resources: – Up to 1,250 MW of economic front office transactions on an annual basis as needed through 2015, taking advantage of favorable market conditions. – At least 200 MW of long-term power purchases. – Cost-effective interruptible customer load contract opportunities (focus on opportunities in Utah). – PURPA Qualifying Facility contracts and cost-effective distributed generation alternatives (Customer-owned standby generation is addressed in Action Item no. 5. • Resources will be procured through multiple means: (1) the All-Source RFP reissued on December 2, 2009, which seeks third quarter summer products and customer physical curtailment contracts among other resource types, (2) periodic mini-RFPs that seek resources less than five years in term, and (3) bilateral negotiations. • Closely monitor the near-term need for front office transactions and reduce acquisitions as appropriate if load forecasts indicate recessionary impacts greater than assumed for the February

Action Item	Category	Timing	Action(s)
			2009 load forecast, or if renewable or thermal plant assets are determined to be cost-effective alternatives. • *Acquire incremental transmission through Transmission Service Requests to support resource acquisition.*
3	**Peaking / Intermediate / Base-load Supply-side Resources**	**2014 - 2016**	Procure through acquisition and/or company construction long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame. • The proxy resource included in the 2010 business plan portfolio consists of a Utah wet-cooled gas combined-cycle plant with a capacity rating of 607 MW, acquired by the summer of 2015. • Procure through the 2008 all-source RFP issued in December 2009. – The Company submitted a benchmark resource, specified as the addition of a second combined cycle block at PacifiCorp's Lake Side Plant. • In recognition of the unsettled U.S. economy, expected continued volatility in natural gas markets, and regulatory uncertainty, continue to seek cost-effective resource deferral and acquisition opportunities in line with near-term updates to load/price forecasts, market conditions, transmission plans, and regulatory developments. – PacifiCorp will reexamine the timing and type of gas resources and other resource changes as part of a comprehensive assumptions update and portfolio analysis to be conducted for the 2008 RFP final short-list evaluation in the RFP approved in Docket UM 1360, the next business plan, and 2008 IRP update.
4	**Plant Efficiency Improvements**	**2010 - 2019**	Pursue economic plant upgrade projects—such as turbine system improvements and retrofits—and unit availability improvements to lower operating costs and help meet the Company's future CO_2 and other environmental compliance requirements. • *Successfully complete the dense-pack coal plant turbine upgrade projects by 2019, which are expected to add 86 MW of incremental capacity in the east and 48 MW in the West with zero incremental emissions.* • *Seek to meet the Company's aggregate coal plant net heat rate improvement goal of 213 Btu/kWh by 2018*[3]. • *Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules.*

[3] *PacifiCorp Energy Heat Rate Improvement Plan*, March 31, 2009.

<table>
<tr><th>Action Item</th><th>Category</th><th>Timing</th><th>Action(s)</th></tr>
<tr><td>5</td><td>Class 1 DSM</td><td>2010 - 2019</td><td>Acquire up to 200 MW of cost-effective Class 1 demand-side management programs for implementation in the 2010-2019 time frame.
• Pursue up to 30 MW of expanded Utah Cool Keeper program participation by 2019; revisit the program's growth assumptions in light of the recent passage of Utah legislation that permits an opt-out program design.
• Pursue up to 100 MW of additional cost-effective class 1 DSM products including commercial curtailment and customer-owned standby generation (55 MW in the east side and 45 MW in the west side) to hedge against the risk of higher gas prices and a faster-than-expected rebound in load growth resulting from economic recovery; procure through the currently active 2008 DSM RFP and subsequent DSM RFPs.
• For 2010, continue to implement a standardized Class 1 DSM system benefit estimation methodology for products modeled in the IRP. The modeling will compliment the supply curve work by providing additional resource value information to be used to evolve current Class 1 products and evaluate new products with similar operational characteristics that may be identified between plans.</td></tr>
<tr><td>6</td><td>Class 2 DSM</td><td>2010 - 2019</td><td>Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2019, equivalent to about 4.1 to 4.6 million MWh.
• Procure through the currently active DSM RFP and subsequent DSM RFPs.</td></tr>
<tr><td>7</td><td>Class 3 DSM</td><td>2010 - 2019</td><td>Acquire cost-effective Class 3 DSM programs by 2018.
• Procure programs through the currently active DSM RFP and subsequent DSM RFPs.
• Continue to evaluate program attributes, size/diversity, and customer behavior profiles to determine the extent that such programs provide a sufficiently reliable firm resource for long-term planning.
• Portfolio analysis with Class 3 DSM programs included as resource options indicated that at least 100 MW may be cost-effective; continue to evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling.</td></tr>
<tr><td>8</td><td>Planning Process Improvements</td><td>2010</td><td>Portfolio modeling improvements.
• For the next IRP planning cycle, complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and renewable portfolio standard (RPS) regulatory requirements at the jurisdictional level. Use the enhanced model to provide more detailed analysis of potential hard-cap regulation of carbon dioxide emissions and achievement of state or federal emissions reduction goals. Also use the capacity expansion model</td></tr>
</table>

Action Item	Category	Timing	Action(s)
			to evaluate the cost-effectiveness of coal facility retirement as a potential response to future regulation of carbon dioxide emissions. • Refine modeling techniques for DSM supply curves/program valuation, and distributed generation. • Investigate and implement, if beneficial, the Loss of Load Probability (LOLP) reliability constraint functionality in the System Optimizer capacity expansion model. • Continue to coordinate with PacifiCorp's transmission planning department on improving transmission investment analysis using the IRP models. • For the next IRP planning cycle, provide an evaluation of, and continue to investigate, intermediate-term market purchase resources for purposes of portfolio modeling. • Consider developing one or more scenarios incorporating plug-in electric vehicles and Smart Grid technologies.
9	**Transmission**	**2009-2011**	Obtain Certificates of Public Convenience and Necessity and conditional use permits for Utah/Wyoming/Idaho segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. • Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Mona and Oquirrh. • Obtain Certificate of Public Convenience and Necessity for 230 kV and 500 kV line between Windstar and Populus. • Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Populus and Hemingway.
10	**Transmission**	**2010**	Complete Utah/Idaho segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. • Complete construction of a 345 kV line between Populus to Terminal.
11	**Transmission**	**2013 - 2014**	*Complete permitting and construction of the Utah segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. Includes:* • *A 500 kV line between Mona and Limber and a 345kV line from Limber to Oquirrh.*

Action Item	Category	Timing	Action(s)
			• *A 345 kV line between Oquirrh and Terminal.*
12	**Transmission**	**2014 - 2016**	*Complete permitting and construction of Wyoming / Idaho / Utah segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. Includes:* • *A 230 kV and 500 kV line between Windstar and Populus.* • *A 345 kV line between Sigurd and Red Butte.*
13	**Transmission**	**2016 - 2018**	*Complete permitting and construction of Idaho segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. Includes:* • *A 500 kV line between Populus and Hemingway.*
14	**Transmission**	**2017 - 2019**	*Complete permitting and construction of the Wyoming/Utah segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief.* • *A 500 kV line between Aeolus and Mona.*
15	**Transmission**	**2010-2011**	Obtain rights of way for the Wallula-McNary line segment by the end of 2010, and complete construction by the end of 2011.
16	**Transmission**	**2010-2019**	For future IRP planning cycles, include on-going financial analysis with regard to transmission, which includes: a comparison with alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects, the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments and base case segments.
17	**Renewables**	**2010**	By August 2, 2010, complete a wind integration study that has been vetted by stakeholders through a public participation process.
18	**Planning Process Improvements**	**2010**	During the next planning cycle, work with parties to investigate carbon dioxide emission levels as a measure for portfolio performance scoring.

Action Item	Category	Timing	Action(s)
19	Planning Process Improvements	2010	In the next IRP, provide information on total CO_2 emissions on a year-to year basis for all portfolios, and specifically, how they compare with the preferred portfolio.
20	Planning Process Improvements	2010	For the next IRP planning cycle, work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.
21	Planning Process Improvements	2010	In the next IRP planning cycle, incorporate assessment of distribution efficiency potential resources for planning purposes.

1. Introduction

This 2008 Integrated Resource Plan (IRP) Update Report describes resource planning activities that occurred subsequent to the filing of the 2008 Integrated Resource Plan in May 2009, and presents the Company's revised 10-year resource portfolio and IRP action plan. These activities centered on preparation of the Company's 10-year business plan for the period 2010-2019 ("2010 business plan").

To support business plan development, PacifiCorp used its capacity expansion optimization model, *System Optimizer*, to help refine the resource portfolio based on updates to forecasted loads, resources, market prices, and other model inputs. The updated resource portfolio also incorporates resource decisions made outside of an optimization modeling context. These resource decisions reflect capital expenditure and operating cost constraints developed by the corporate finance department with input from the PacifiCorp business units (PacifiCorp Energy, Pacific Power, and Rocky Mountain Power). The financial constraints ensure that the business plan is financially supportable and affordable to customers, while at the same time complying with all regulations and the MidAmerican Energy Holdings Company (MEHC) PacifiCorp acquisition commitments.

This report first describes the planning environment for 2009, focusing on PacifiCorp's business planning development, resource procurement initiatives, emissions/climate change regulatory outlook, and the Energy Gateway transmission planning (Chapter 2). Next, Chapters 3 and 4 describe the changes to key inputs and assumptions relative to those used for the 2008 IRP. The updated high-level resource portfolio is then presented along with associated changes to the 2008 IRP action plan and Energy Gateway transmission strategy action plan (Chapters 5 and 6). Appendix A consists of additional load forecast information and a more detailed resource portfolio table.

2. Planning Environment

Business Plan Development

PacifiCorp's 2010 business planning process began in April 2009 with preparation of a preliminary business plan scenario. Preparation of the formal business plan submission to MEHC ("version 1") and a revised plan submission ("version 2") was conducted in May-August and August-October of 2009, respectively. The 2010 business plan was approved by the MEHC Board on December 9, 2009.

A main finding of the 2010 business planning process was that given the current load forecast and the economic downturn, the operating and capital budgets supporting the 2009 business plan would not maintain a capital structure that is optimal for both customers and the Company, and would increase rate pressure on customers. For example, assessment of the initial projected capital budget with resource acquisitions and resultant cash flows indicated difficulty in maintaining current debt ratings. As a consequence, PacifiCorp reexamined the need and timing for capital investments and, where appropriate and feasible, the business plan eliminates or defers investments. The revised capital budget included expenditure reductions on the order of $3.5 billion in the early years of the plan, relative to the budget established for the 2009 business plan.

Against this backdrop, allocating capital for transmission expansion is a precondition for maintaining transmission system reliability, supporting future load obligations, and accessing new and existing resource areas. PacifiCorp also assumed that making investments in environmental controls for sulfur oxides (SO_X) and nitrous oxides (NO_X) was needed unless the emission control requirements are modified.

Another key business planning consideration is the progress and challenges associated with the Energy Gateway transmission expansion project. In an effort to maintain schedule flexibility, in-service dates have been updated to provide flexibility while maintaining the urgency to complete the project. These date adjustments, combined with the lack of additional transmission capacity on the existing system, prompted deferral of planned wind resources dependent on the availability of new transmission. PacifiCorp will continue its focus on maintaining system reliability and efficient use of new and existing transmission as additional operational experience is gained with large-scale and rapid wind penetration in certain areas of the system.

At least two factors could change the Company's decision to defer additional renewable energy resources until 2017. First, as the particulars regarding federal emissions reduction regulations become clearer, it may be prudent to resume adding renewable energy sooner than 2017. Second, the Company remains open to acquiring renewable energy projects that represent economically attractive and unique opportunities for its customers. This aspect of the updated IRP action plan remains unchanged.

RESOURCE PROCUREMENT UPDATE

All Source Request for Proposals

PacifiCorp issued its latest all-source Request for Proposals (RFP) on December 2, 2009. This RFP represents the successor to the all-source RFP ("2008 All-Source RFP") that was suspended on April 6, 2009, and seeks up to 1,500 MW of base-load, intermediate-load, and third-quarter market purchases (front office transactions) on a system-wide basis for the 2014-to-2016 period. The minimum eligible fixed term is five years for the proposals, with a minimum dependable capacity of 100 MW. Exceptions to these term and capacity limitations include (1) a power purchase agreement ("PPA") or tolling service agreement ("TSA") not backed by an asset, (2) load curtailment, (3) PURPA Qualifying Facilities, and (4) dispatchable/schedulable renewable resources. Proposals were due March 1, 2010. Procurement decisions for this RFP are expected in January 2011.

Renewables Requests for Proposals

PacifiCorp decided to not issue a RFP for renewable resources during 2010 after assessing the capital budget and the conditions impacting renewable energy development such as transmission availability. The Company's revised renewables resource strategy is summarized in Chapter 6.

Demand-side Management Requests for Proposals

The Company released a comprehensive demand-side management RFP (2008 DSM RFP) in November 2008. The initial 2008 DSM RFP work schedule proved to be too ambitious given the number of bidder proposals, Utah DSM program recovery filings, American Reinvestment and Recovery coordination efforts, compliance reporting for Washington Initiative 937, and other regional activities. In 2009 PacifiCorp evaluated all proposals received and developed a short list of proposals. Those vendors having proposals on the short-list were asked to provide an additional year for the company to fully evaluate and process the short-listed proposals. The revised timeline for the remaining short-listed proposals is fourth quarter 2010.

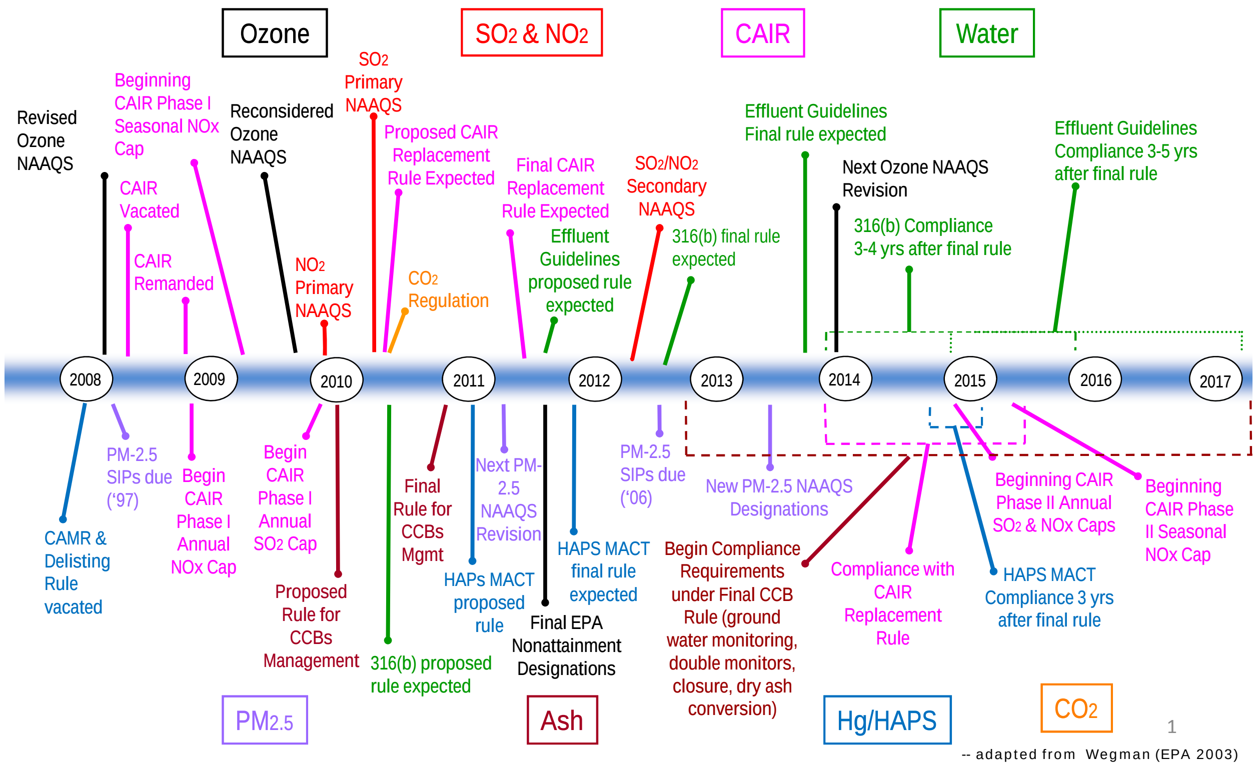
The Company completed an RFP for program evaluations of legacy products in 2009, and selected Cadmus, Inc. to perform the work. Draft evaluations are scheduled for mid-year 2010, and at that time, will be provided to interested parties for review and comment. Current agreements for engineering resources in support of commercial, industrial and agricultural program delivery expires in June 2010. The RFP to re-procure these services, as well as for general program evaluation services, is scheduled to be released during the first quarter of 2010. The RFP for continuation of Utah and Idaho load management program services is also scheduled to be released in the first quarter of 2010 as are RFPs for the delivery of the company's refrigeration recycling and Home Energy Savings programs.

EMISSIONS AND CLIMATE CHANGE POLICY

Currently Regulated Emissions

There are currently a multitude of environmental regulations which are in various stages of being promulgated, as outlined on the timeline below (Figure 2.1). Each of these regulations will have an impact on the utility industry and could affect environmental control requirements, limit operations, change dispatch, and could ultimately determine the economic viability of PacifiCorp's generation assets. The U.S. Environmental Protection Agency has undertaken a multi-pronged approach to minimize air, land, and water-based environmental impacts. Aside from potential greenhouse gas regulation, no single regulation is likely to materially impact the industry; however, in concert they are expected to have a significant impact – especially on the coal-fueled generating units that supply approximately 50% of the nation's electricity.

Figure 2.1 – Environmental Regulatory Timeline at the Federal Level



Climate Change

On June 26, 2009, the U.S. House of Representatives passed The American Clean Energy and Security Act of 2009 (H.R. 2454) authored by Congressmen Henry Waxman of California and Edward Markey of Massachusetts. The Bill seeks to reduce greenhouse gas emissions via a complex cap and trade system affecting the vast majority of the United States economy. Although the cap and trade requirements would generally apply only to sources responsible for greenhouse gas emissions of at least 25,000 metric tons per year, the Bill sets no emissions threshold for power plants and certain other industries.

The cap consists of a series of annually decreasing limits on overall United States greenhouse gas emissions, beginning with a 3 percent reduction in 2012 (compared to 2005 levels), reaching a 17 percent reduction by 2020, and ultimately an 83 percent reduction by 2050. The Bill would initially apply to electric utilities, fuel refineries, and certain industries (representing 66 percent of total United States emissions), with additional industrial sources covered in 2014, and natural gas distributors added in 2016, ultimately bringing about 85 percent of the United States greenhouse gas emissions within the cap and trade system. The U.S. Environmental Protection Agency would distribute emission allowances (collectively equal to the annual overall emissions cap) among affected emitters, who must annually hold a sufficient number of allowances and offset credits to equal their actual emissions. Electric utilities would initially receive 35 percent of the available allowances for free; however, the free allocation for this sector is completely phased out between 2026 and 2030, with a transition to a full auction.

The bill also allows capped sources to use up to two billion metric tons of domestic and international offset credits to meet a portion of their annual compliance obligations. Offsets are generated by projects that reduce, avoid, or sequester emissions that would otherwise not be subject to the emissions cap.

On November 5, 2009, a substantially similar bill, the Clean Energy Jobs and American Power Act (S. 1733) authored by Senators Boxer of California and Kerry of Massachusetts, passed the Senate Environment and Public Works Committee. Some of the key differences between the Senate bill and the House bill are listed in Table 2.1.

Table 2.1 – Comparison of Waxman-Markey and Kerry-Boxer bills

Waxman – Markey (H.R. 2454)	Kerry – Boxer (S. 1733)
17% reduction by 2020 (from 2005)	20% reduction by 2020 (from 2005)
Small deficit reduction pool in early years	Deficit reduction pool of 10% - 25%
2012 Electric Sector allocation: 2.0 billion	2012 Electric Sector allocation: 1.7 billion
Standard auction price floor: $10 (2009$) Strategic auction price floor: $28 (2009$)	Standard auction price floor: $10 (2005$) Strategic auction price floor: $28 (2005$)
Domestic offsets: 1.0 billion metric tons/year International offsets: 1.0 billion metric tons/year	Domestic offsets: 1.5 billion metric tons/year International offsets: 0.5 billion metric tons/year

Environmental Protection Agency's Advance Notice of Public Rulemaking

On an independent, yet parallel path, the U.S. Environmental Protection Agency (EPA) is also pursuing the potential regulation of greenhouse gas emissions. On April 2, 2007, the U.S. Supreme Court held that greenhouse gas emissions, including carbon dioxide, are air pollutants covered by the Clean Air Act. (Massachusetts v. Environmental Protection Agency). The Supreme Court held that the Environmental Protection Agency was required to determine whether or not emissions of greenhouse gases from new motor vehicles cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare.

In April 2009, the Environmental Protection Agency responded to the Supreme Court's holding by proposing a finding that greenhouse gases do contribute to air pollution that may endanger public health or welfare. The Environmental Protection Agency finalized its Endangerment Finding on December 7, 2009. The agency also expects to issue final regulations under the Clean Air Act to control greenhouse gas emissions from light duty vehicles at the end of March 2010. The EPA has taken the position that such an action will trigger Clean Air Act permitting requirements for stationary sources under the New Source Review/Prevention of Significant Deterioration, and Title V Operating Permit programs for greenhouse gas emissions.

To address the significant number of stationary sources that will become subject to regulation under the New Source Review/Prevention of Significant Deterioration and Title V operating permit program in March 2010, the Environmental Protection Agency on October 27, 2009 issued a proposed Prevention of Significant Deterioration and Title V greenhouse gas emissions tailoring rule to "tailor" the major source applicability thresholds for greenhouse gas emissions under the Prevention of Significant Deterioration and Title V programs of the Clean Air Act and to set a Prevention of Significant Deterioration significance level for greenhouse gas emissions. If the New Source Review/Prevention of Significant Deterioration programs were applied literally under the Clean Air Act, the thresholds would be set at extremely low levels—up to 250 tons—for greenhouse gas emissions. To avoid the situation in which very small sources of greenhouse gas emissions are required to obtain permits, based on the legal doctrines of "absurd results" and "administrative necessity", this proposed rule would phase in the applicability thresholds for both the Prevention of Significant Deterioration and Title V programs for sources of greenhouse gas emissions. The first phase, which would last six years, would establish a temporary level for the Prevention of Significant Deterioration and Title V applicability thresholds at 25,000 tons per year carbon dioxide equivalent, and a temporary Prevention of Significant Deterioration significance level for greenhouse gas emissions of between 10,000 and 25,000 tons per year carbon dioxide equivalent. After the first six years, the Environmental Protection Agency would conduct a study to assess this program and potentially revise the applicability and significance level thresholds.

The Environmental Protection Agency plans to finalize its "Tailoring Rule" prior to or at the same time it finalizes its light-duty vehicle greenhouse gas emissions standards in March 2010. Sources with the potential to emit greenhouse gas emissions above the established thresholds will be required to obtain permits if they construct a new source or modify an existing source. Likewise, existing sources will be required to incorporate greenhouse gas emissions in their Title V operating permits. Sources cannot currently determine what constitutes the required Best Available Control Technology for new or modified sources, nor can they anticipate how the Title V permit requirements may impact their facilities.

Impacts and Sources

Relatively speaking, the potential requirements to reduce greenhouse gas emissions could have a profound impact on PacifiCorp's generation fleet. In the near term (e.g., through at least 2020), to reach the emissions caps proposed in the federal bills, PacifiCorp would need to consider converting coal units to burn natural gas and retiring other coal units and replacing them with lower carbon emitting resources and expanded DSM. In the longer term, replacement of baseload fossil-fueled plants with non-emitting baseload resources currently in development (e.g., carbon-sequestered thermal units, new generation nuclear units, and renewable generation supplemented with battery storage) will be necessary to achieve reduction targets such as those in the federal bills, assuming continuation of the energy policy that requires electric utilities provide service on demand in the quantity demanded.[4]

While federal legislation requiring reduction in greenhouse gas emissions coupled with a mandatory allowance trading market would be expected to have the greatest financial impact on PacifiCorp, the potential for impacts resulting from the changes in New Source Review/Prevention of Significant Deterioration provisions from the greenhouse gas tailoring rule are also likely to have an influence on capital/construction projects, even when installing emissions controls. The requirement to conduct a Best Available Control Technology review and implement additional efficiency measures or otherwise reduce greenhouse gas emissions is likely to have a chilling effect on future projects.

EPRI analysis of Waxman-Markey

In 2009, the Electric Power Research Institute (EPRI) conducted a broad-brush study to identify and analyze the likely effects of H.R. 2454 for U.S. generators and customers. The study relied upon the NEMS (National Energy Modeling System) used by the U.S. Department of Energy's Energy Information Agency (EIA) and their Annual Energy Outlooks and policy analyses. NEMS and detailed EIA results are publicly available.

[4] In addition to the costs of replacing and retrofitting coal and natural gas generation, bills such as Waxman-Markey and Boxer-Kerry would impose an additional cost that ultimately will be borne by customers. This added cost is the cost of purchasing emissions allowances, even for emissions that are below the cap. Although the bills provide for some allocation of "free" allowances, PacifiCorp is expected to receive less than 50% of the allowances it needs even if the Company is able to reduce emissions to the level of the cap, and the expected shortfall increases each year. Beginning in 2012, the financial impact of such a shortfall is estimated to be $581 million to $683 million per year (assuming $25 per allowance), and increasing each year thereafter. In order to mitigate these significant allowance costs, PacifiCorp would need to make significant changes in its generation portfolio.

EPRI has worked extensively with NEMS for over a decade. For the study, EPRI applied the model to represent Waxman-Markey on behalf of PacifiCorp, using PacifiCorp's assumptions on power plant costs (vintage 2008). The PacifiCorp/EPRI team then established set scenarios with a goal to better understand the role of modeling assumptions in assessing climate policy impacts on energy sector. A reference case was defined as having a full 2 billion tons of offsets availability, plus three offsets sensitivity cases that phase-in offsets from zero:

- Case 1 "Plentiful" 2 Billion Tons by 2030
- Case 2 "Scarce" 1 Billion Tons by 2030
- Case 3 "Very Scarce" half Billion Tons by 2030

Waxman-Markey allows up to 2 billion tons/year of offset use (50%-50% split between domestic and international sources with some opportunity for substitution). Offset quantities allowed in legislation far exceed experiences in Europe's CO_2 trading system. If low-cost offsets are unavailable in quantities approved by the program, much higher allowance prices will be required to meet cap. The study also concluded that market and regulatory uncertainty in offset supply dominates all other uncertainties in impacting the price of carbon. Abundant offsets allow the economy to meet the emissions cap with only limited abatement from the regulated entities covered by the cap-and-trade program. If offsets are limited, most of the abatement is done by the electric sector through the increased use of natural gas and the increased installation of wind generation.

A PowerPoint presentation summarizing study results and entitled *"Preliminary Analysis of Waxman-Markey (H.R.2454) Using NEMS for PacifiCorp"* is available for downloading from PacifiCorp's IRP website.[5]

ENERGY GATEWAY TRANSMISSION PROGRAM PLANNING

The Energy Gateway transmission project remains a critical component of the short and long-term resource acquisition plans, representing a precondition for maintaining transmission system reliability, supporting future load obligations, and accessing new and existing resource areas.

[5] The link to the document is: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Environment/WM-NEMS-Roadshow-draft-9-11-09.pdf.

Construction of the first segment (Populus to Terminal) is underway and remains on schedule for completion in 2010. Populus to Terminal is a new double-circuit 345 kilovolt ("kV") transmission line from the Populus substation near Downey, Idaho to the Terminal substation in Salt Lake City, Utah. The Populus to Terminal line will be placed in service in two phases. The first phase from the Ben Lomond substation (near Ogden, Utah) to the Terminal substation will be in service by June 2010, and the second phase from the Populus substation to the Ben Lomond substation will be in service by December 31, 2010.

As an extension of ongoing transmission planning efforts, Idaho Power and PacifiCorp also recently signed a Memorandum of Understanding ("MOU") that outlines a process to fully define and develop joint ownership of extensive transmission facilities, including the Boardman to Hemingway transmission project and the Gateway West Project. The two companies already share a partnership on Gateway West. Joint ownership of the Hemingway to Boardman project is a new development and is expected to replace further near-term review and consideration of the Hemingway to Captain Jack project listed as "under review" in the 2008 IRP.

Despite this progress, permitting and other related factors require that in-services dates on other segments of Energy Gateway continue to remain flexible. In an effort to maintain schedule flexibility, in-service dates have been updated to allow flexibility while maintaining the urgency to complete the project. The 2010 business plan and associated resource acquisition decisions account for these date adjustments. As issues are addressed and uncertainties eliminated, the Company will continue to adjust its project planning accordingly.

Table 2.2 summarizes the Energy Gateway target in-service date ranges with respect to the dates cited in the 2008 IRP. These date changes are also reflected in the revised transmission action items cited in Chapter 6.

Table 2.2 – Energy Gateway Project Completion Date Changes

Energy Gateway Segment	Completion Date or Date Range	
	2010 Business Plan	2008 IRP
Segment C: Mona to Limber to Oquirrh	2013	2012
Segment C: Oquirrh to Terminal	2013-2014	2012
Segment D: Windstar to Aeolus to Bridger to Populus	2014-2016	2014
Segment E: Populus to Hemingway	2016-2018	2016
Segment F: Aeolus to Mona	2017-2019	2017

In regard to the Walla Walla to McNary project (Segment A), during 2009 PacifiCorp received requests for transmission service, requiring that the Company proceed with the Wallula, Washington to Umatilla, Oregon portion of the Walla Walla to McNary Project transmission line. This section of the Walla Walla to McNary Project is approximately 30 miles in length and will be built on a 125-foot-wide right of way connecting the existing Wallula substation and the McNary substation at Umatilla. Constructing this portion of the line will provide the capacity to add new renewable energy to the system, improve service to customers and improve the reliability of the regional transmission system.

PacifiCorp will work with property owners to obtain rights of way for the Wallula-McNary transmission line segment by the end of 2010. Construction is expected to begin soon thereafter, with plans to bring the new line into service in late 2011. At this point, the Company has not determined when it will construct the Walla Walla to Wallula portion of the McNary Project.

3. Resource Needs Assessment Update

Load Forecast

For the final 2010 business plan, PacifiCorp updated its load forecast in October 2009. Relative to the load forecast prepared in February 2009, PacifiCorp system sales and coincident peak dropped for the planning period, with the largest declines occurring in the early years. The main driver for the residential, commercial and industrial class declines is the effect of the economic downturn.

Tables 3.1 and 3.2 report the October 2009 annual load and coincidental peak load forecasts, respectively. Note that this forecast data excludes load reduction projections from new energy efficiency measures (Class 2 DSM), since such load reductions are included as resources in the System Optimizer model. Tables 3.3 and 3.4 show the forecast changes relative to the February 2009 load forecast for loads and coincident system peaks, respectively.[6]

Table 3.1 – Forecasted Annual Load Growth, 2010 through 2019 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2010	59,403,758	14,146,530	4,483,577	946,287	24,294,698	10,022,709	3,311,467	2,198,489
2011	61,110,064	14,380,455	4,512,495	972,669	24,943,199	10,352,917	3,722,405	2,225,925
2012	63,264,583	14,843,483	4,563,202	1,002,346	25,968,093	10,837,133	3,796,971	2,253,356
2013	65,126,386	15,062,869	4,571,700	1,015,802	26,918,298	11,357,516	3,919,407	2,280,793
2014	66,912,337	15,205,085	4,590,154	1,026,562	27,795,597	11,896,327	4,090,398	2,308,214
2015	68,375,219	15,303,232	4,607,980	1,036,984	28,508,281	12,454,198	4,128,899	2,335,646
2016	69,814,947	15,423,718	4,637,827	1,050,642	29,306,675	12,861,601	4,171,422	2,363,061
2017	70,674,381	15,446,754	4,643,972	1,058,194	29,804,384	13,128,929	4,201,648	2,390,500
2018	71,745,215	15,535,683	4,676,978	1,072,219	30,382,350	13,412,924	4,247,146	2,417,916
2019	72,870,856	15,648,922	4,708,154	1,086,040	30,966,450	13,723,600	4,292,333	2,445,357
Annual Average Growth Rate for 2010-2019								
	2.3%	1.1%	0.5%	1.5%	2.7%	3.6%	2.9%	1.2%

Table 3.2 – Forecasted Annual Coincidental Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2010	**9,883**	2,246	750	153	4,546	1,251	595	342
2011	**10,198**	2,284	759	158	4,667	1,292	686	352
2012	**10,539**	2,348	792	164	4,834	1,342	700	359
2013	**10,831**	2,387	777	167	5,004	1,402	725	368

[6] Portfolio evaluation for the 2008 IRP used a load forecast prepared in November 2008 as well as the February 2009 forecast.

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2014	**11,122**	2,418	788	166	5,153	1,463	757	377
2015	**11,355**	2,436	795	169	5,271	1,525	774	384
2016	**11,585**	2,452	803	171	5,411	1,569	788	391
2017	**11,755**	2,463	809	177	5,511	1,601	795	398
2018	**11,951**	2,476	844	177	5,610	1,633	805	406
2019	**12,112**	2,493	828	179	5,715	1,669	814	413
Annual Average Growth Rate for 2010-2019								
	2.3%	1.2%	1.1%	1.8%	2.6%	3.2%	3.5%	2.1%

Table 3.3 – Annual Load Growth Change: October 2009 Forecast Less February 2009 Forecast

(Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2010	**(2,200,076)**	(664,299)	138,664	(19,931)	(227,614)	(624,102)	(439,352)	(363,441)
2011	**(2,153,866)**	(541,054)	141,092	(32,284)	(461,378)	(835,960)	(63,552)	(360,729)
2012	**(1,765,360)**	(272,213)	145,934	(34,935)	(200,550)	(1,008,781)	(32,492)	(362,322)
2013	**(1,339,859)**	(96,750)	147,601	(39,840)	33,851	(896,380)	(55,402)	(432,939)
2014	**(1,066,760)**	(18,382)	146,837	(44,542)	113,376	(777,969)	1,412	(487,493)
2015	**(971,432)**	19,747	144,145	(47,191)	15,897	(634,574)	10,807	(480,264)
2016	**(897,247)**	41,307	141,185	(49,626)	118,509	(688,358)	17,252	(477,516)
2017	**(884,964)**	44,754	137,258	(51,686)	207,723	(779,177)	23,357	(467,194)
2018	**(972,390)**	22,531	134,696	(54,426)	240,362	(880,891)	31,164	(465,826)
2019	**(596,393)**	57,999	137,249	(55,975)	373,664	(687,219)	41,108	(463,219)
Annual Average Change for 2010-2019								
	(1,284,835)	(140,636)	141,466	(43,044)	21,384	(781,341)	(46,570)	(436,094)

Table 3.4 – Annual Coincidental Peak Growth Change: October 2009 Forecast Less February 2009 Forecast

(Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2010	**(271)**	(149)	13	(5)	7	(56)	(54)	(27)
2011	**(276)**	(135)	13	(8)	(35)	(80)	12	(43)
2012	**(258)**	(98)	10	(9)	4	(97)	(5)	(64)
2013	**(192)**	(75)	14	(9)	38	(87)	(12)	(60)
2014	**(43)**	(67)	13	(11)	41	(74)	74	(18)
2015	**(60)**	(65)	13	(11)	20	(60)	66	(23)
2016	**(98)**	(65)	12	(12)	36	(66)	43	(45)
2017	**(109)**	(68)	11	(12)	45	(77)	37	(45)
2018	**(143)**	(75)	7	(12)	46	(89)	35	(56)
2019	**(86)**	(74)	11	(12)	62	(68)	35	(40)
Annual Average Change for 2010-2019								
	(154)	(87)	12	(10)	26	(75)	23	(42)

The primary drivers for load forecast growth changes by customer class are summarized below.

- Residential – Lower customer growth as a result of the economic slowdown.
- Commercial – Lower customer growth, which is slightly offset by higher commercial sales growth attributable to several new data centers added in both the east and west
- Industrial – In the western states, industrial sales have decreased as a result of the economic downturn. The wood product sector has been hit the hardest. In the eastern states, industrial sales to the oil and gas extraction, processing and transportation sector have also declined.

Appendix A provides additional tables showing the October 2009 forecast net of Class 2 DSM load reductions.

CHANGES TO EXISTING AND FIRM PLANNED RESOURCES

Existing Supply-Side Resources

Since the filing of the 2008 IRP in May 2009, PacifiCorp has added 268 megawatts of additional renewable resources. Table 3.5 reports these renewable resources by category, nominal capacity (MW), and commercial on-line date.

Table 3.5 – Renewable Resource Additions

Resource Category	Nominal Capacity (MW)	On-line Date
Owned Wind		
High Plains	99.0	9/13/2009
McFadden Ridge I	28.5	9/29/2009
Purchased Wind - Power Purchase Agreements and PURPA Qualifying Facilities		
Three Buttes Wind, LLC (PPA)	99.0	12/31/2009
Four Corners Windfarm LLC (Oregon Wind Farm II, QF)	10.0	6/16/2009
Four Mile Canyon Windfarm LLC (Oregon Wind Farm II, QF)	10.0	6/16/2009
Threemile Canyon Wind LLC (QF)	9.9	9/1/2009
Biogas – PURPA Qualifying Facilities		
Small Oregon QF	1.6	5/15/2009

The Company also entered into a number of firm market purchase and exchange contracts, classified by the Company as "Front Office Transactions". Front office transactions represent contracts for standard market products acquired on a forward basis typically for a one-to-three year term. Table 3.6 summarizes the purchases and exchange agreements made subsequent to the filing of the 2008 IRP, identifying the contract type and location, contract capacity (MW), and contract term. These agreements all constitute seasonal third-quarter products.

Table 3.6 – Contract Additions: Front Office Transactions

Contract Type - Location	Contract Capacity (MW)	Contract Term
Purchases		
FOT 3rd Qtr – Mona	50	2010-2012
FOT 3rd Qtr – Mona	100	2011-2012
Locational Spreads		
FOT 3rd Qtr – Mona	100	2012-2013
FOT 3rd Qtr – Four Corners	100	2012-2013
FOT 3rd Qtr – Mona	50	2013
FOT 3rd Qtr – Mona	50	2012-2013

Existing Demand-side Management

In 2009, peak load reductions from participating Class 1 DSM program participants grew by 96 MW, from 345 MW targeted in the 2008 IRP to 441 MW of actual program participation.

The first-year historical energy and capacity savings (1992-2009) associated with Class 2 DSM program activity has accounted for over 3.8 million megawatt hours and roughly 700 megawatts of load reductions.

For Class 3 DSM, System-wide participation in metered time-of-day and time-of-use programs as of December 31, 2009 was about 20,400 customers. Approximately 1.40 million residential customers—96% of the Company’s residential customer base—are subject to inverted rate plans either seasonally or year-around.

In 2009 the Utah Public Service Commission approved a Company outreach and communication program designed to increase public understanding and awareness of Rocky Mountain Power’s DSM programs. This is the first “cost only” program to be introduced into Utah’s demand-side portfolio on the premise that the outreach will increase the overall performance of all demand-side programs in the state. Similar outreach and communication programs are being considered for Washington, Idaho and Wyoming provided the portfolio performance in those states can support the additional costs.

Firm Planned Supply-Side Resources

Future supply-side resources are categorized as "firm planned" if they are under construction, included in the Company's construction budget, or are purchases for which a contract has been signed. The significant changes to firm planned resources include (1) the addition of the Dunlap I and Top of the World wind projects in 2010, (2) removal of the Swift 1 hydro turbine upgrades, and (3) a reduction in coal plant turbine upgrade capacity. Table 3.7 reports the resource additions and subtractions accounted for in the 2010 business plan.

Table 3.7 – Changes to Firm-Planned Resources

Wind	Capacity (MW)	Expected Online Date
Additions – Owned and Purchased Wind		
Dunlap I (Company-owned)	111.0	11/30/2010
Top of the World Wind LLC (PPA)*	200.2	12/31/2010
Casper Wind (Qualifying Facility)	16.5	12/1/2009
Additions – Small Hydro, PURPA Qualifying Facilities[7]		
Small Oregon Qualifying Facility	0.8	4/1/2010
Small Oregon Qualifying Facility	5.0	9/1/2010
Removals		
Swift 1 hydroelectric turbine upgrades	75.0	2012-2014
Coal and gas plant turbine upgrades[8]	34.7	2009-2019

* This PPA is a 20-year agreement resulting from the Company's renewable resource Request for Proposals, "2008R-1", issued January 26, 2009.

Firm Planned Demand-side Management

Planned Class 1 DSM peak load reductions increased from 525 MW in the 2008 IRP to 566 MW for the 2010 business plan. The increase is primarily driven by greater irrigation load management program participation than forecasted and the addition of a commercial load management program in 2010. Contributions from these two programs are forecasted to nearly offset the reduction in Utah's Cool Keeper air conditioning program forecast in the 2010 business plan. The Cool Keeper reduction was prompted

[7] Two additional small hydroelectric Qualifying Facilities, for a total of 1.8 MW, will be included in the next planning cycle.

[8] Coal and gas plant turbine upgrades were changed by removing some upgrades and deferring others. The 2008 IRP Preferred Portfolio included 169.9 megawatts of upgrades, whereas the 2010 business plan includes 135.2 megawatts.

by a decision by the Public Utility Commission of Utah to deny the Company's November 2008 request to modify the Cool Keeper program design from an opt-in to opt-out participation model. This action removed the Company's ability to grow the program as planned in the 2008 IRP, absent legislative action. For the purposes of the 2010 business plan, the Cool Keeper expansion was decreased from 200 MW to about 30 MW. However, legislation was proposed in January 2010 intended to enable the opt-out design. The legislation passed in the Utah Legislature in March 2010. As a result, the Company will revisit program growth assumptions in coordination with the Utah DSM Advisory Group.

UPDATED CAPACITY BALANCE

Historical DSM Adjustment

Increasing the load forecast to account for the historical DSM included in the forecast ensures the appropriate quantities of Class 2 DSM are accounted for in the capacity expansion model. Table 3.8 shows the impact of the historical DSM energy adjustments to the annual system coincident peak loads used in the capacity load and resource balance. (Note that this upward load adjustment applies only for capacity expansion modeling purposes. The Company's official load forecast, included in Appendix A, is reported net of this DSM adjustment.)

Table 3.8 – Historical DSM Adjustment to Coincident Peak Forecast

Year	Historical DSM Adjustment (MW)	System Coincident Peak Prior to Adjustment (MW)	Adjusted System Coincident Peak (MW)
2010	37	9,883	9,920
2011	73	10,198	10,272
2012	110	10,539	10,648
2013	147	10,831	10,977
2014	183	11,122	11,306
2015	220	11,355	11,575
2016	256	11,585	11,841
2017	294	11,755	12,049
2018	330	11,951	12,281
2019	367	12,112	12,479

Figure 3.1 compares the annual capacity positions for the 2008 IRP and the 2010 business plan, covering 2010 through 2019. Both assume a 12 percent planning reserve margin (PRM). The 2010 business plan capacity position does not become short until

2012 versus 2011 for the 2008 IRP. This difference is attributed to both a lower load forecast as well as the resource changes described above.

Figure 3.2 shows the 2010 business plan's capacity peak load and resource gaps for the system for 2010 through 2019 if no additional resources are acquired (the initial load & resource balance). Table 3.9 reports the capacity load and resource line items for the Eastern Control Area, Western Control Area, and the system. Table 3.10 reports the line item differences between the capacity balances for the 2008 IRP and the 2010 business plan.

Figure 3.1 – Capacity Position Comparison, 2008 IRP versus the 2010 Business Plan

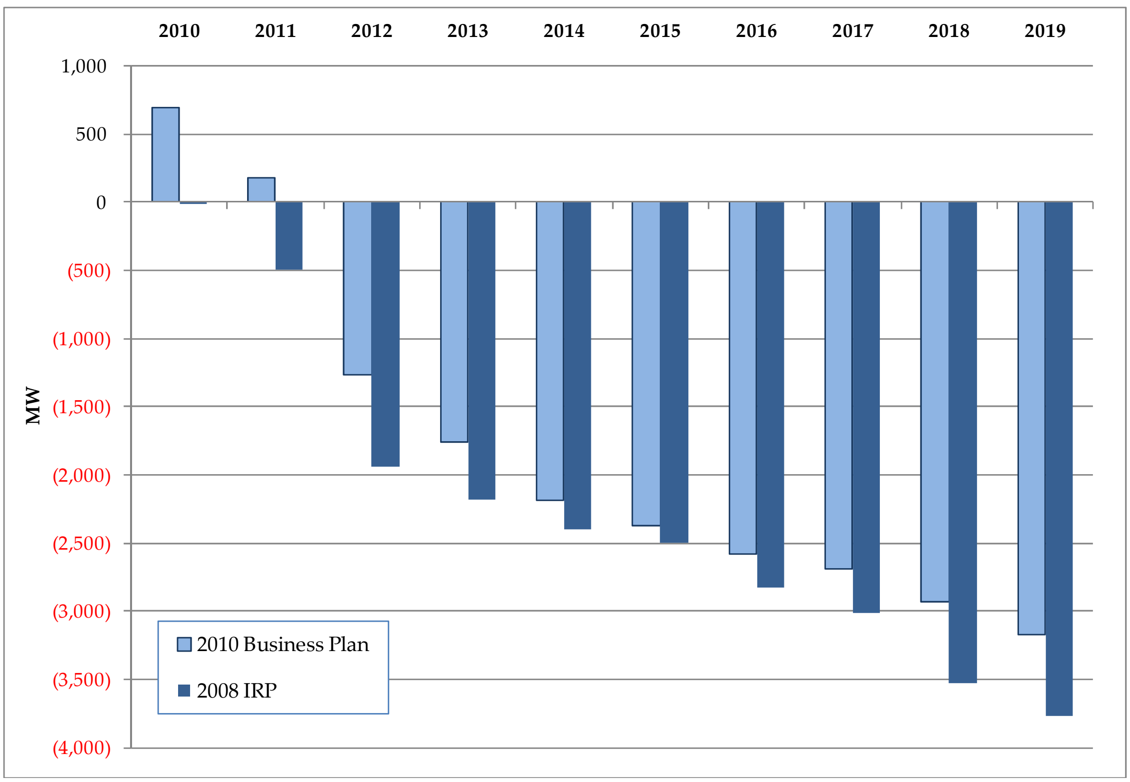


Figure 3.2 – System Coincident Peak Loads and Resources, 2010 Business Plan

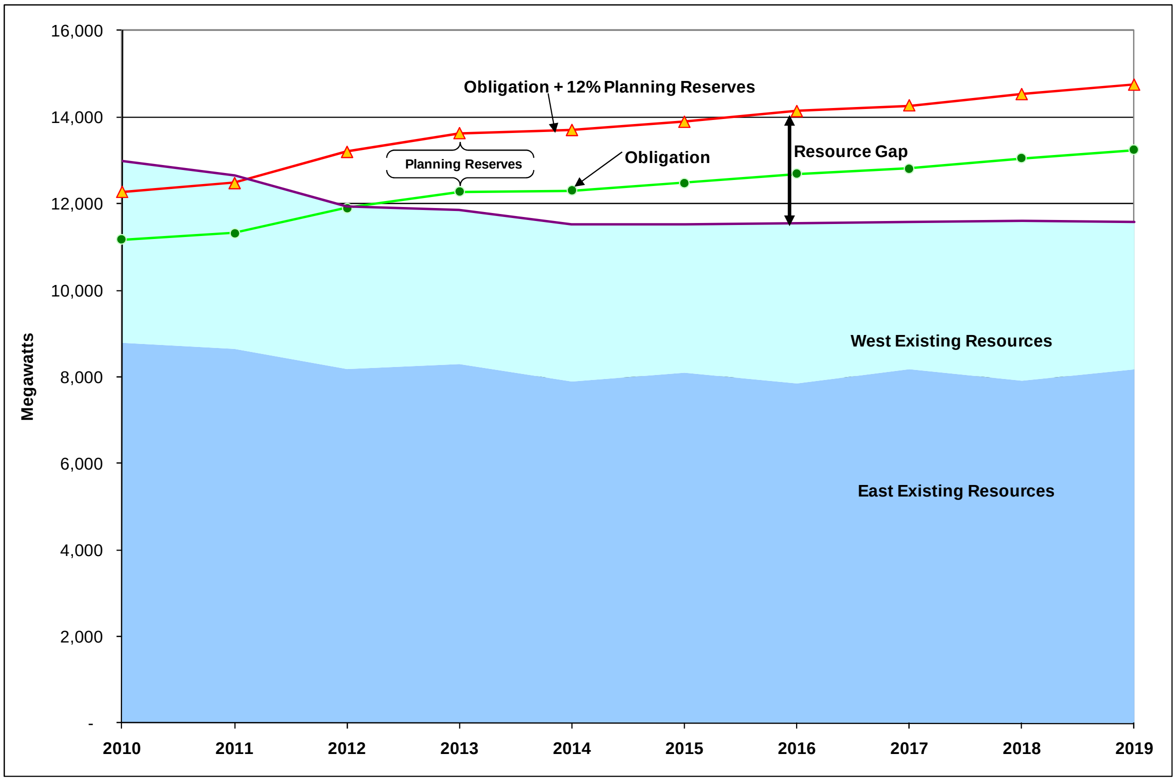


Table 3.9 – Capacity Load and Resource Balance, Megawatts (12% Target Reserve Margin)

Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
East										
Thermal	5,989	6,009	6,009	6,011	6,011	6,022	6,059	6,059	6,059	6,059
Hydroelectric	132	132	132	132	132	132	132	132	132	132
Class 1 DSM	458	463	468	468	468	468	468	468	468	468
Renewable	157	157	157	157	157	154	154	154	154	154
Purchase	560	655	705	604	304	304	283	283	283	283
Qualifying Facilities	152	152	152	152	152	152	152	152	152	152
Interruptible	327	327	327	327	327	327	327	327	327	327
Transfers	1,000	738	218	432	330	524	260	589	323	584
East Existing Resources	8,775	8,633	8,168	8,283	7,881	8,084	7,835	8,164	7,898	8,159
Load	6,753	7,036	7,292	7,577	7,846	8,070	8,295	8,461	8,628	8,804
Sale	768	758	997	1,045	745	745	745	659	659	659
East Obligation	7,521	7,794	8,289	8,622	8,591	8,815	9,040	9,120	9,287	9,463
Planning Reserves (12%)	741	762	815	867	899	926	955	965	985	1,006
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	812	832	885	937	969	996	1,026	1,035	1,055	1,077
East Obligation + Reserves	8,332	8,626	9,174	9,559	9,561	9,811	10,066	10,156	10,343	10,540
East Position	443	7	(1,006)	(1,276)	(1,680)	(1,728)	(2,230)	(1,991)	(2,444)	(2,380)
East Reserve Margin	18%	12%	(0%)	(3%)	(8%)	(8%)	(13%)	(10%)	(14%)	(13%)
West										
Thermal	2,554	2,554	2,554	2,554	2,554	2,554	2,566	2,564	2,572	2,584
Hydroelectric	1,128	1,135	977	976	976	982	982	982	978	925
Class 1 DSM	-	-	-	-	-	-	-	-	-	-
Renewable	77	77	71	71	71	71	71	71	71	71
Purchase	1,297	856	247	281	226	221	225	255	269	285
Qualifying Facilities	144	138	135	135	135	135	135	135	135	135
Transfers	(1,000)	(739)	(219)	(432)	(329)	(523)	(260)	(588)	(323)	(585)
West Existing Resources	4,200	4,021	3,765	3,585	3,633	3,439	3,718	3,418	3,702	3,414
Load	3,166	3,236	3,355	3,400	3,459	3,504	3,546	3,588	3,653	3,674
Sale	490	290	258	258	258	158	108	108	108	108
West Obligation	3,656	3,526	3,613	3,658	3,717	3,662	3,654	3,696	3,761	3,782
Planning Reserves (12%)	283	320	404	405	419	413	412	413	419	420
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	290	327	410	412	425	419	418	419	426	426
West Obligation + Reserves	3,945	3,853	4,024	4,070	4,142	4,081	4,072	4,115	4,186	4,208
West Position	255	168	(259)	(485)	(510)	(642)	(354)	(698)	(485)	(794)
West Reserve Margin	19%	17%	5%	(1%)	(2%)	(6%)	2%	(7%)	(1%)	(9%)
System										
Total Resources	12,975	12,653	11,933	11,868	11,514	11,523	11,554	11,582	11,600	11,574
Obligation	11,176	11,319	11,902	12,280	12,308	12,477	12,694	12,816	13,048	13,245
Reserves	1,101	1,159	1,296	1,349	1,395	1,416	1,444	1,455	1,481	1,503
Obligation + Reserves	12,277	12,478	13,197	13,629	13,703	13,893	14,138	14,271	14,529	14,748
System Position	698	175	(1,264)	(1,761)	(2,189)	(2,370)	(2,584)	(2,689)	(2,929)	(3,174)
Reserve Margin	18%	14%	1%	(2%)	(6%)	(7%)	(8%)	(9%)	(10%)	(12%)

Table 3.10 – 2010 Business Plan Capacity Balance Less 2008 IRP Capacity Balance, Megawatts

Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
East										
Thermal	(9)	(15)	(57)	(55)	(67)	(56)	(27)	(29)	196	195
Hydroelectric	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Class 1 DSM	63	28	3	(7)	(17)	(27)	(37)	(47)	(57)	(57)
Renewable	-	-	-	-	-	-	-	-	-	-
Purchase	13	113	363	263	(37)	(37)	(37)	(37)	(37)	(37)
Qualifying Facilities	1	1	1	1	1	1	1	1	1	1
Interruptible	90	90	90	90	90	90	90	90	90	90
Transfers	48	136	(204)	(8)	100	34	(244)	324	(91)	323
East Existing Resources	202	349	193	280	67	1	(258)	299	99	511
Load	(196)	(114)	(112)	(66)	67	41	(8)	(30)	(68)	(47)
Sale	-	-	250	300	-	-	-	-	-	-
East Obligation	(196)	(114)	138	234	67	41	(8)	(30)	(68)	(47)
Planning Reserves (12%)	(43)	(41)	(38)	(13)	4	2	(3)	(4)	(8)	(5)
Non-owned reserves	-	-	-	-	-	-	-	-	-	-
East Reserves	(43)	(41)	(38)	(13)	4	2	(3)	(4)	(8)	(5)
East Obligation + Reserves	(239)	(155)	100	221	71	43	(11)	(34)	(76)	(52)
East Position	442	505	93	60	(4)	(41)	(247)	334	174	563
East Reserve Margin	6%	6%	1%	1%	0%	(0%)	(3%)	4%	2%	6%
West										
Thermal	(5)	(14)	(25)	(37)	(37)	(37)	(25)	(13)	(5)	7
Hydroelectric	(89)	(81)	(3)	(33)	(70)	(176)	(168)	(167)	(168)	(174)
Class 1 DSM	-	-	-	-	-	-	-	-	-	-
Renewable	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)
Purchase	94	103	132	137	115	110	114	144	130	156
Qualifying Facilities	24	18	15	15	15	15	15	15	15	15
Transfers	(47)	(136)	203	10	(101)	(34)	244	(325)	92	(325)
West Existing Resources	(42)	(129)	303	73	(97)	(141)	161	(365)	45	(340)
Load	(256)	(254)	(232)	(238)	(263)	(265)	(278)	(305)	(325)	(313)
Sale	-	-	-	-	-	-	-	-	-	-
West Obligation	(256)	(254)	(232)	(238)	(263)	(265)	(278)	(305)	(325)	(313)
Planning Reserves (12%)	(42)	(43)	(44)	(45)	(45)	(45)	(47)	(54)	(55)	(56)
Non-owned reserves	-	-	-	-	-	-	-	-	-	-
West Reserves	(42)	(43)	(44)	(45)	(45)	(45)	(47)	(54)	(55)	(56)
West Obligation + Reserves	(298)	(297)	(276)	(283)	(308)	(310)	(325)	(359)	(380)	(369)
West Position	256	168	579	356	212	169	486	(6)	425	29
West Reserve Margin	7%	5%	15%	8%	4%	3%	12%	(2%)	9%	(1%)
System										
Total Resources	160	220	496	353	(30)	(139)	(97)	(66)	144	171
Obligation	(452)	(368)	(94)	(4)	(196)	(224)	(286)	(335)	(393)	(360)
Reserves	(85)	(84)	(82)	(58)	(42)	(43)	(50)	(58)	(62)	(61)
Obligation + Reserves	(537)	(452)	(176)	(62)	(238)	(267)	(336)	(393)	(455)	(421)
System Position	698	673	672	415	208	128	239	327	599	592
Reserve Margin	6%	6%	6%	3%	1%	1%	1%	2%	4%	4%

Referencing Table 3.10, the significant differences in line item amounts reflect the changes to existing and firm planned resources documented above, as well as the following additional changes.

East Changes

- Thermal – The large increase in 2018 is attributable to a change in the assumed life of the Gadsby gas plants (Units 1-3). The plant life was extended past the planning period rather than ending in 2017. The annual decreases in thermal capacity reflect the 2010 business plan's modified coal and gas plant turbine upgrade schedule.
- Purchases – In addition to new front office transaction contracts, the modeling of the Southeast Idaho exchange contract with the Bonneville Power Administration was updated with new non-owned resource information for the control area, thereby lowering capacity.
- Interruptible contracts – The positive change reflects the inclusion of the operating reserve component of the Monsanto interruptible load contract (90 MW) in addition to the economic curtailment portion previously modeled.
- Market sales – Changes for years 2012 and 2013 are due to the recent front office transaction contract additions.

West Changes

- Thermal – The capacity decreases reflect project deferrals associated with the 2010 business plan's coal plant turbine upgrade schedule.
- Hydro – In addition to the removal of the Swift 1 turbine upgrade project, the decrease in hydro capacity reflects a change to how the Grant PUD Meaningful Priority contract right (107 MW on an average annual basis) is handled. This contract includes an annual physical power election option. Since the Company performs analysis every year to determine whether to elect the physical power, the decision was made to remove it from forward years. The Company still receives the Reasonable Portion Revenues spread whether or not the Meaningful Priority is elected.
- Renewable Resource and Qualifying Facilities – The Oregon Wind Farm I / II were reclassified from the Renewables Resource category to the Qualifying Facility category, explaining the 19 MW capacity decrease shown.
- Purchases – The increase is due to the new load forecast for the Southeast Idaho exchange contract, which reflects the return of energy from the Bonneville Power Administration.

4. MODELING ASSUMPTIONS UPDATE

This chapter describes the key modeling assumption changes relative to the 2008 IRP. The areas covered include natural gas and electricity market prices, CO_2 emission costs and compliance, the transmission topology, resource costs, and renewable portfolio standard (RPS) compliance.

NATURAL GAS AND POWER MARKET PRICE UPDATES

PacifiCorp used the September 30, 2009 official forward price curves ("September 2009 curves") for development of the final 2010 business plan. For the final 2008 IRP modeling, PacifiCorp used forward price curves developed in October 2008.

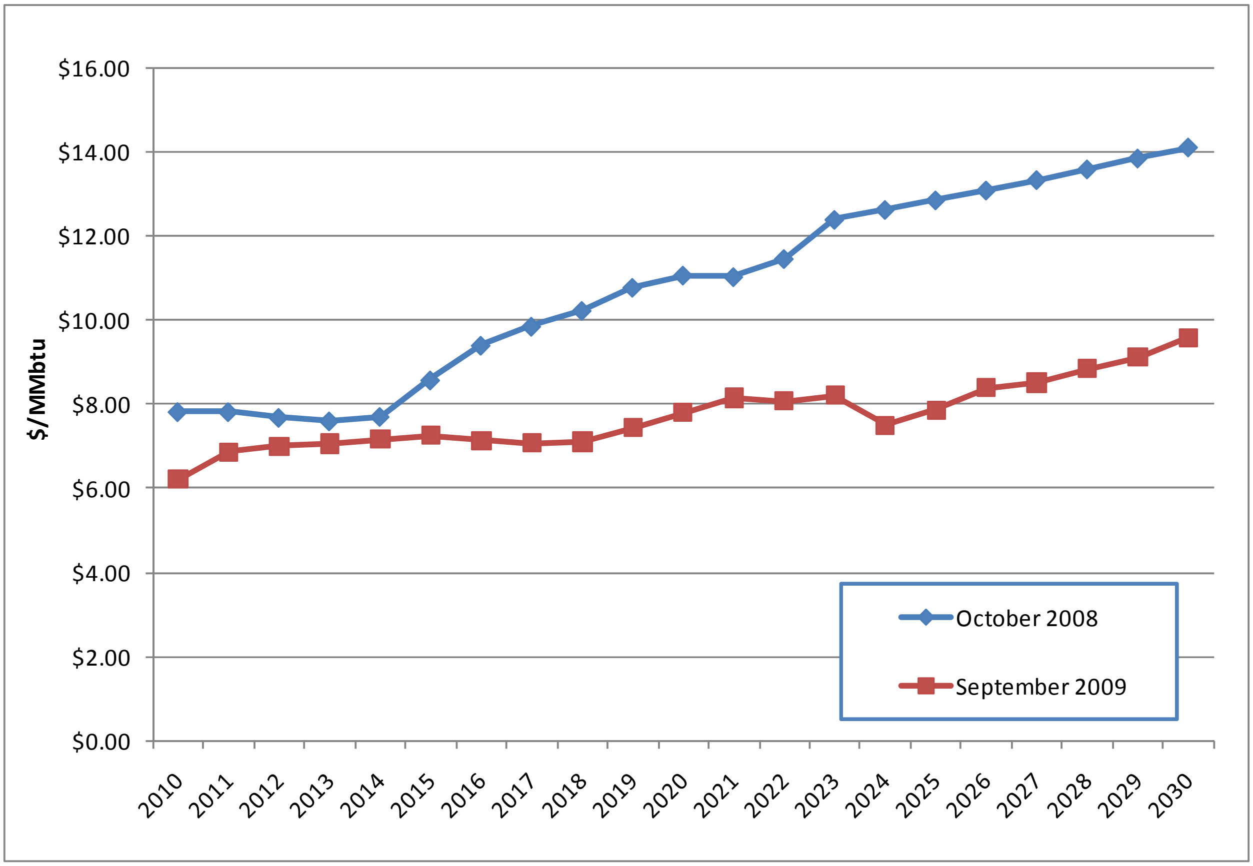
Consistent with past practice, price curves are developed with market forwards for the first six years, a blending of market forwards and a fundamentals forecast for year seven, and a pure fundamentals forecast for subsequent years. These price curve components are used for both natural gas and electricity prices. The fundamentals forecast for natural gas is selected from a variety of external sources with consideration given to underlying supply/demand assumptions, forecast documentation, peer-to-peer forecast price comparisons, date of issuance, and forecast horizon. The fundamentals forecast for natural gas is then a key input to the internally derived estimation of the fundamentals forecast for electricity, which is produced with MIDAS, a chronological hourly dispatch model covering the Western Interconnect.

Natural Gas Market Prices

The September 2009 natural gas price curve is based upon an external long-term gas price forecast issued in June 2009 and a short term gas price forecast issued in August 2009. Figure 4.1 compares the nominal annual Henry Hub natural gas prices from the October 2008 and September 2009 curves.

The September 2009 natural gas curve reflects a fundamentals forecast influenced by cost effective domestic supply opportunities largely due to growth in unconventional shale gas plays. The amount of unconventional domestic supply underlying the September 2009 natural gas curve is larger than what was assumed in the fundamentals forecast underlying the October 2008 natural gas curve. Expectations for domestic unconventional supply tripled by 2025 in the fundamental forecast underlying the September 2009 curve relative to the fundamentals forecast used for the October 2008 curve. As shown in the figure below, the projected influx of unconventional domestic supplies into the North American natural gas market lowers long-term prices considerably.

Figure 4.1 – Henry Hub Natural Gas Prices (Nominal)



Power Market Prices

The electricity price fundamentals forecast is developed with the MIDAS model, an hourly chronological dispatch model for the Western Interconnect. The natural gas fundamentals forecast described above is a key input to the MIDAS model, and consequently, the decline in electricity prices from the October 2008 curve to the September 2009 curve is consistent with the decline in natural gas prices. Figures 4.2 through 4.4 compare the average annual electricity prices for the Palo Verde and Mid-Columbia market hubs from the October 2008 and September 2009 curves.

Figure 4.2 – Average Annual Flat Palo Verde Electricity Prices

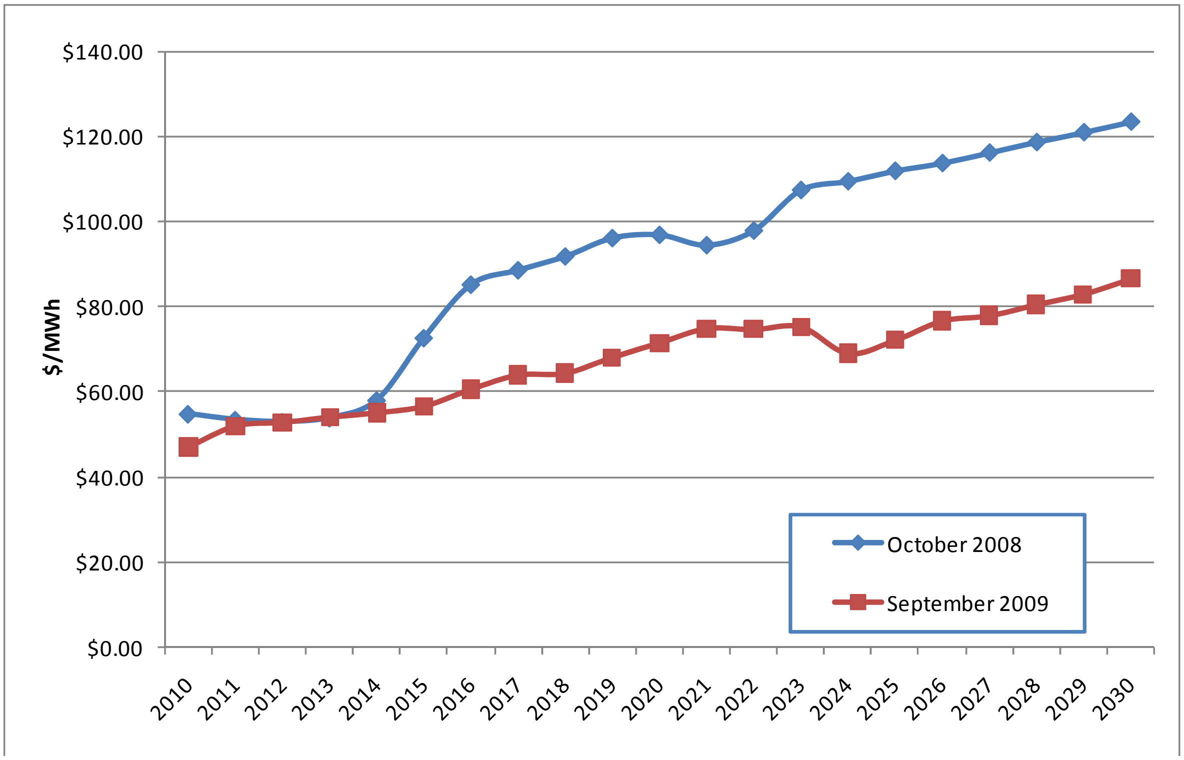


Figure 4.3 – Average Annual Heavy Load Hour Palo Verde Electricity Prices

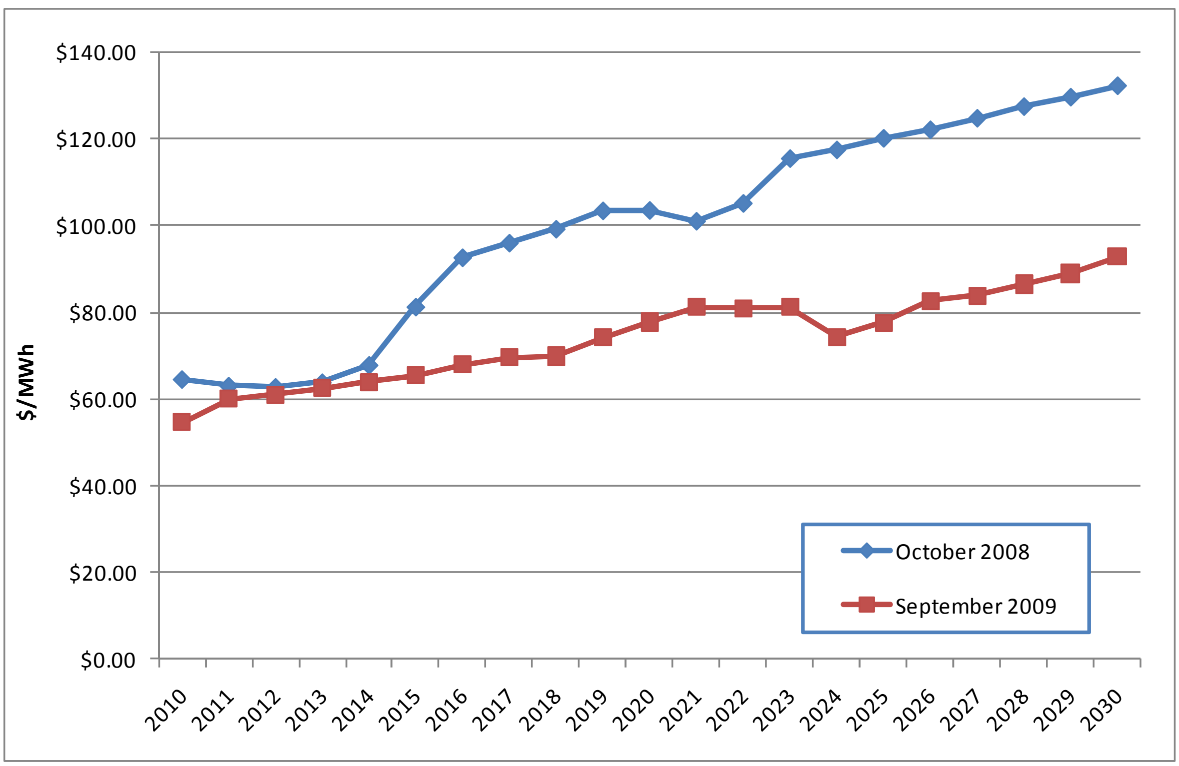
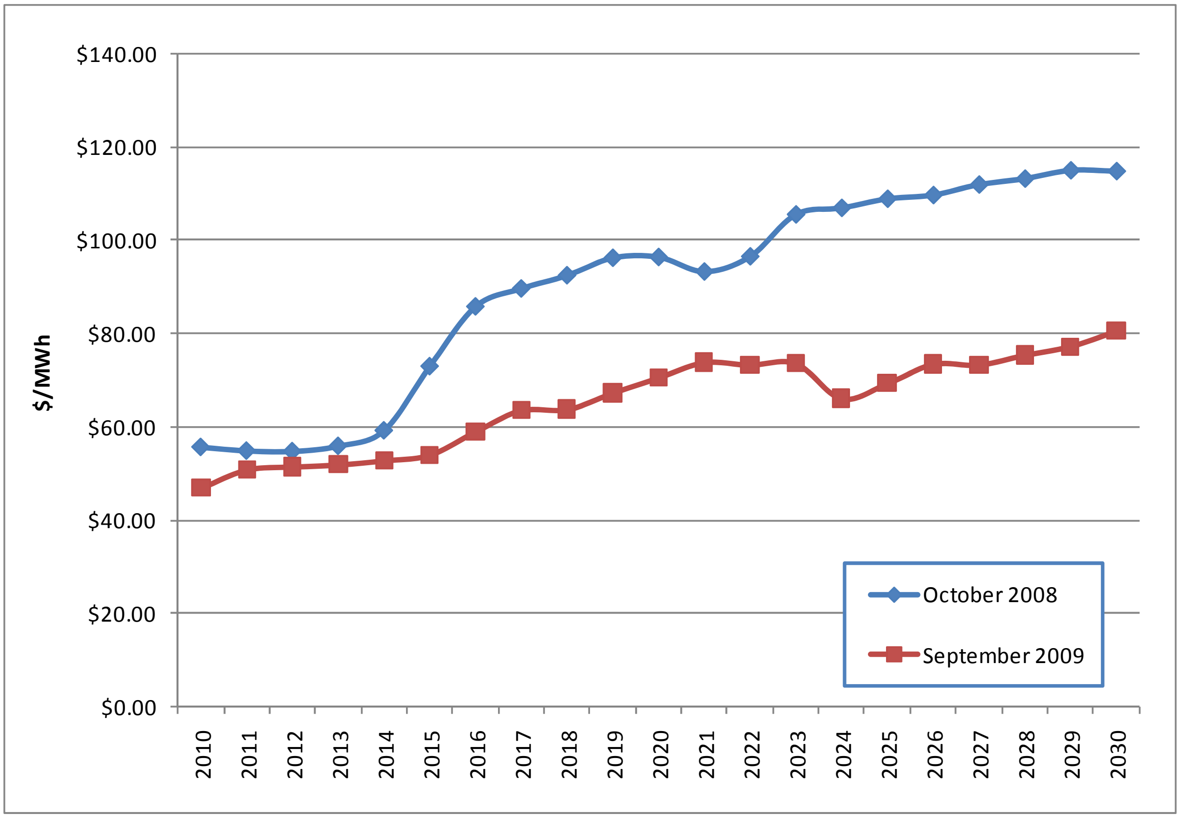


Figure 4.4 – Average Annual Flat Mid-Columbia Electricity Prices



CARBON DIOXIDE EMISSIONS COST AND COMPLIANCE

For the 2010 business plan, the assumed CO_2 compliance mechanism was a cap & trade system, whereas for the 2008 IRP, the compliance mechanism was a CO_2 tax. Table 4.1 contrasts the modeling assumptions for the 2008 IRP and 2010 business plan.

The use of the $8/ton price starting point for the 2010 business plan reflects continued uncertainty regarding CO_2 price signals for existing fossil fuel generation during the 10-year business planning period. However, as noted in Chapter 5, the Company used a $45/ton CO_2 allowance price starting point to develop resource targets for Class 2 DSM, and initial targets for wind. The $45/ton CO_2 allowance price serves as a reasonable proxy for an RPS compliance price, and helps to capture CO_2 risk mitigation benefits for these resource types.

Table 4.1 – Comparison of Carbon Dioxide Emissions Modeling Assumptions

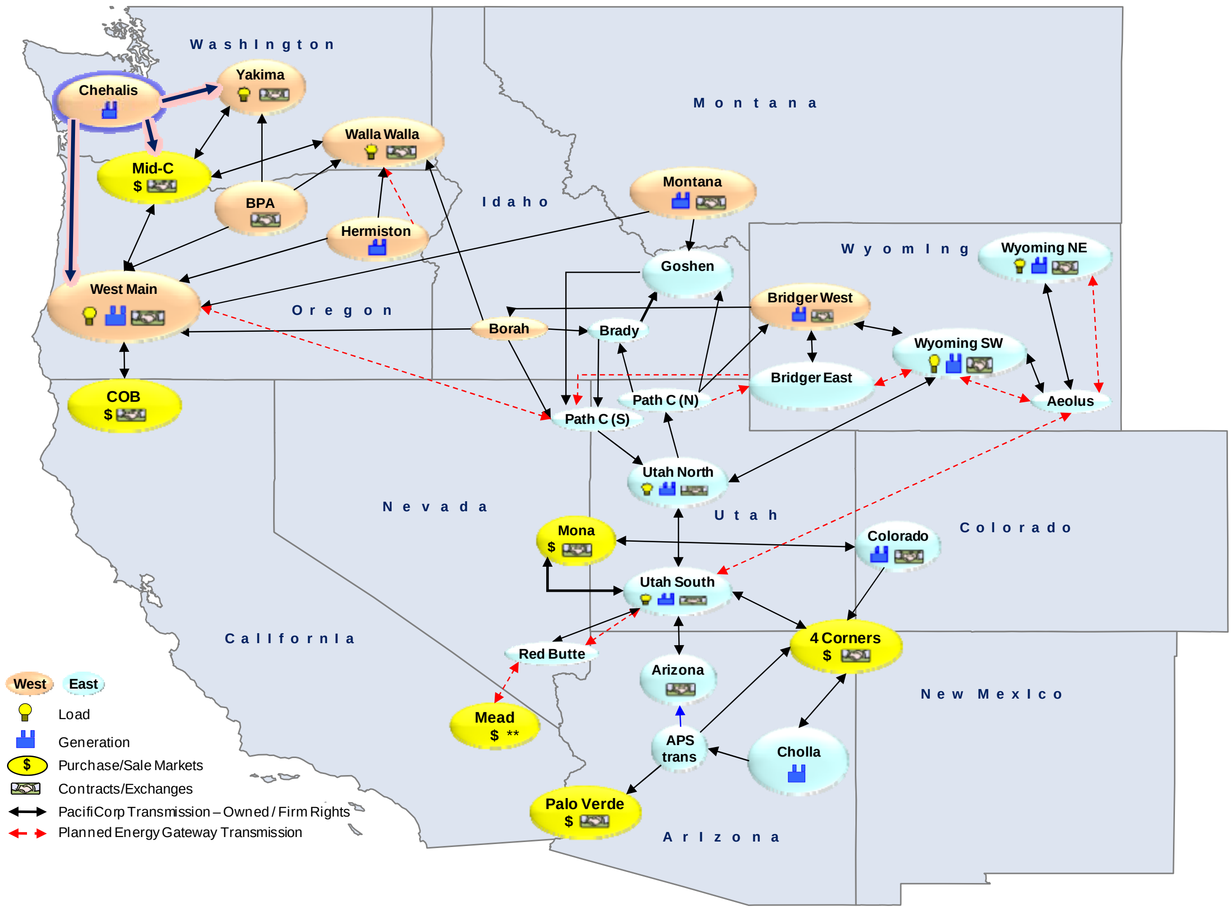
2008 IRP	2010 Business Plan
• Emission tax system • For portfolio development, defined 2013 starting values at \$0, \$45, \$70, and \$100 per short ton (in 2008 dollars), escalated at 2% / year inflation rate • For stochastic production cost modeling, simulated portfolios with \$0, \$45, and \$100 per ton values	• Cap & trade system based on emissions at the retail level • Emission cap: 37.3 million tons by 2020 (17% lower than 2005 levels) • \$8 CO_2 allowance price starting in 2013 (in 2008 dollars), escalated at 1.8% / year; annual values are as follows:

Year	U.S. CO_2 Prices (Nominal $/short ton)
2010	\$0.00
2011	\$0.00
2012	\$0.00
2013	\$8.58
2014	\$8.74
2015	\$8.90
2016	\$9.06
2017	\$9.22
2018	\$9.38
2019	\$9.55

Transmission Topology

The transmission topology used for the 2008 IRP update reflects the addition of a new transmission area (or "bubble") to refine the representation of firm transmission rights associated with the Chehalis gas-fired combined cycle plant acquired in 2007. Figure 4.5 shows the transmission system topology with the new Chehalis bubble in Washington and its links to other west-side bubbles (West Main, Mid-Columbia market, and Yakima).

Figure 4.5 – Transmission Topology



FRONT OFFICE TRANSACTIONS

For the 2010 business plan, the most significant change to annual front office transaction (FOT) acquisition limits was to eliminate the need to access the Nevada-Utah Border (NUB) market hub due to the acquisition of Nevada Power transmission service from Mead into Utah starting in 2012, as well as lower projected load growth. The maximum availability of Mona FOT was also increased from 200 MW to 300 MW beginning in 2013. Table 4.2 compares the FOT annual limit assumptions made for the 2008 IRP and 2010 business plan by market hub and the two proxy resource types modeled: seasonal heavy load hour (3rd quarter 6x16) and flat annual (7x24) products.

Table 4.2 – Front Office Transaction Annual Limit Assumptions

Market Hub / Proxy FOT Product	2008 IRP	2010 Business Plan
Mead / 3rd Quarter 6x16	• 600 MW in 2017 and beyond	• 300 MW in 2012 – 2014 • 100 MW in 2015 – 2016 • 0 MW in 2017 +
Mona / 3rd Quarter 6x16	• 200 MW in 2009 and beyond	• 200 MW in 2009 – 2012 • 300 MW in 2013 and beyond
Nevada-Utah Border / 3rd Quarter 6x16	• 164 MW in 2012 • 579 MW in 2013	• Hub not incorporated
Utah / 3rd Quarter 6x16	• 50 MW	• 50 MW
West Main / 3rd Quarter 6x16	• 50 MW	• 50 MW
Mid-Columbia / Flat 7x24 and 3rd Quarter 6x16	• 400 MW + 300 MW with 10% price premium	• 400 MW
COB / Flat 7x24 and 3rd Quarter 6x16	• 400 MW	• 400 MW

CLASS 2 DSM SUPPLY CURVES

PacifiCorp modeled Class 2 DSM in a manner consistent with the approach used for the 2008 IRP: via supply curve resource options available by load area, year, and levelized cost range. The supply curve DSM potentials were updated to directly account for the impact of the forthcoming federal residential lighting standards specified in the Energy Independence and Security Act (EISA) of 2007. In contrast, for the 2008 IRP, the Company handled the impact of the federal lighting standards as adjustments to the load forecast fed into the System Optimizer model.

Consistent with the Northwest Power and Conservation Council's methodology at the time, it was assumed that 15 percent of residential compact fluorescent lighting (CFL) potential falls outside of the scope of the EISA standards, and could be acquired in equal amounts from 2010 through 2014. After 2014, there would be no CFL potential due to the standards. The resulting load reduction estimates were spread over the end-use load shapes to create the updated supply curve load shapes input into System Optimizer.[9]

RESOURCE CAPITAL COSTS

PacifiCorp modified capital costs for the 2010 business plan based on information available in the fall of 2009. The costs reflect adjustments to account for expected real decreases due to the on-going recession, general inflation, and industry demand for the

[9] The supply curve update was performed by The Cadmus Group, Inc., the firm that developed the original supply curves for the 2008 IRP.

various generation options. For combine-cycle plants (CCCTs), the capital costs also incorporate adjustments reflecting continued efforts to develop a second phase at the Lake Side facility.

Table 4.3 shows the capital costs by generation resource type considered for the 2010 business plan, as well as changes with respect to those used for the 2008 IRP.

Table 4.3 – Resource Capital Cost Comparison, 2010 Business Plan vs. 2008 IRP

	Capital Cost by Resource Type (2009 $/kW)		
Resource Type and Location	**2010 Business Plan**	**Difference, 2010 Business Plan less 2008 IRP**	**Percent Change**
East			
Natural Gas, Intercooled Aero SCCT	1,084	32	3%
Natural Gas, SCCT Frame	770	23	3%
Natural Gas, CCCT 2x1 (4500 feet elev.)	1,886	15	1%
Wind	2,332	(234)	(9%)
West			
Natural Gas, Intercooled Aero SCCT	985	29	3%
Natural Gas, SCCT Frame	700	21	3%
Natural Gas, CCCT 2x1 (1500 feet elev.)	1,714	13	1%
Natural Gas, CCCT 2x1 (Sea level elev.)	$1,629	13	1%
Wind	$2,474	(137)	(5%)

RENEWABLE PORTFOLIO STANDARD COMPLIANCE

Throughout the 2010 business planning process, resource portfolios were evaluated against forecasts of renewable portfolio standard compliance requirements. These requirements consider the Company's updated retail load forecasts, load reductions from demand-side management programs, existing qualifying renewable resources based on state-specific RPS eligibility criteria, and estimates of renewable energy credit sales.

The following key assumptions were updated for the renewable portfolio standard compliance analysis:

- Use of the October 25, 2009 load forecast

- Use of the System Optimizer Class 2 DSM resource expansion plan, described in Chapter 5.
- Qualifying renewable resources under state-specific renewable portfolio standard programs were updated to 1,686 MW, which includes 600 MW of additions needed in 2020 through 2022 to comply with an assumed federal RPS requirement that reaches 20 percent by 2025 (the Waxman-Markey Bill).
- Estimates for sale of renewable energy credit were included, with no sales beyond 2012 due to anticipated federal or greenhouse gas legislation.

In addition to the existing state RPS requirements, on July 22, 2009, Oregon Governor Ted Kulongoski signed into law House Bill 3039, which includes a large-scale (500 kW to no more than 5 MW) electric utility solar capacity standard. [10] The law requires electric utilities in the state to acquire 20 MW (alternating-current basis) of owned or purchased nameplate solar photovoltaic (PV) capacity by January 1, 2020. Each utility's requirement is based on its share of the state's 2008 retail electricity sales. PacifiCorp's estimated requirement developed during 2010 business plan preparation was 8.8 MW. This capacity is reflected in the Company's 2010 business plan resource portfolio.

[10] Enrolled House Bill 3039, July 2009, Section 3.

5. Portfolio Development

PacifiCorp used the System Optimizer capacity expansion optimization model to develop resource portfolios based on inputs and assumptions updated throughout the business planning process. Portfolio modeling conducted for the preliminary 2010 business plan scenario is described first. Next, the portfolio development approach for the formal business plan submissions to MEHC is described. For this portfolio development, the Company devised a number of resource targets outside of the modeling effort, and treated these targets as fixed resource schedules in subsequent capacity expansion modeling. Finally, the business plan portfolio is presented.

Preliminary 2010 Business Plan Scenario

The purpose of the preliminary business plan scenario was to construct an early view of where the Company stands in regard to new resource requirements, net power costs, financing, and other critical factors that determine business plan decisions. A key goal was identification of the challenges in developing an affordable and financially sustainable business plan in light of deteriorating economic conditions, volatile market conditions, regulatory uncertainty, and the Company's ambitious capital spending plans. Preliminary scenario development relied on updated information available at the time, including the February 2009 load forecast, the March 31, 2009 official forward price curves, recent rate case outcomes, and modified transmission assumptions, including the March 2009 Energy Gateway transmission plan. (No changes to emission costs, resource costs, or resource availability, were incorporated in the scenario development.)

The resource portfolio modeling, which used the 2008 IRP preferred portfolio as the starting point, indicated that new gas plant capacity could be deferred by one year: 2014 to 2015 for a combined-cycle plant, and 2016 to 2017-2018 for simple-cycle units. These resource deferrals were made possible by assuming that Energy Gateway transmission access to the Mead market in Nevada was available in 2014 rather than the 2017 date assumed for the 2008 IRP. Front office transaction availability at Mona also was increased from 200 MW to 300 MW beginning in 2013. (See Table 4.2 for a comparison of front office transaction availability assumptions for the 2010 business plan and 2008 IRP). Note that this portfolio modeling did not include the Energy Gateway completion date deferrals documented in Chapter 2.

2010 BUSINESS PLAN SUBMISSIONS

As noted above, this phase of portfolio development consisted of both capacity optimization modeling as well as determination of resource capacity targets added as fixed resources in the capacity expansion model. Modeling strategies by resource type are described below.

Resource Modeling Strategies

Thermal Resources

PacifiCorp allowed the System Optimizer model to select the type and timing of gas-fired resources for the business plan portfolio, subject to revised earliest in-service dates for the resource options. (Coal-fired plants were not included as resource options pending clarification of federal greenhouse gas emissions reduction requirements.) In-service dates were moved out one year relative to those used for the 2008 IRP and preliminary business plan scenario. For example, the earliest in-service date for conventional combined-cycle plants was changed from 2013 to 2014, while the date for intercooled aeroderivative simple-cycle combustion turbine plants was changed from 2012 to 2013.

Class 1 Demand-side management

PacifiCorp's DSM department developed the Class 1 DSM targets for the 2010 business plan. These targets were informed by DSM RFP activities and program expansion efforts. The Class 1 DSM targets were treated as fixed resources in the System Optimizer model. Table 5.1 shows the new Class 1 DSM targets used for the 2010 business plan. The DSM resources consist of the Cool Keeper and irrigation programs, as well as an "Other" direct load control (DLC) category that includes residential air conditioning, commercial curtailment, and customer-owned distributed standby generation (DSG).

Table 5.1 – Class 1 Demand-side Management Cumulative Additions

Capacity (MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Existing Program Expansions										
Utah - Cool Keeper	18	23	28	28	28	28	28	28	28	28
Idaho Irrigation	12	12	12	12	12	12	12	12	12	12
Utah Irrigation	13	13	13	13	13	13	13	13	13	13
New programs										
Irrigation (CA, OR, WA)	0	3	12	20	20	20	20	20	20	20
Other DLC (OR, UT, WY) *	0	7	30	60	75	78	78	78	78	78

* Other direct load control consists of residential air conditioning and commercial curtailment programs including customer-owned distributed standby generation.

Note that for the 2010 business plan, customer-owned standby generation was combined with the commercial curtailment program category under Class 1 DSM. In contrast, commercial curtailment was categorized as a separate generation resource for the 2008 IRP.

Table 5.2 compares the 2010 business plan's total cumulative capacity targets for new Class 1 programs with those in the 2008 IRP Preferred Portfolio through 2019.

Table 5.2 – New Class 1 Demand-side Management Capacity Comparison

IRP Year	Resources	Resource MW	Total MW
2008 IRP	**Existing**		
	Irrigation	220	
	Utah – Cool Keeper	100	
	Subtotal - Existing Class 1 DSM		**320**
	New		
	Utah – Cool Keeper	205	
	Distributed Standby Generation (DSG)	50	
	Subtotal - New Class 1 DSM		**255**
	Total Class 1 DSM + DSG		**575**
2010 Business Plan	**Existing**		
	Utah - Cool Keeper	100	
	Idaho Irrigation	275	
	Utah Irrigation	40	
	Subtotal - Existing Class 1 DSM		415
	New		
	Utah – Cool Keeper	28	
	Idaho Irrigation	12	
	Utah Irrigation	13	
	Irrigation - CA, OR, WA	20	
	Commercial Curtailment including DSG	78	
	Subtotal - New Class 1 DSM		151
	Total Class 1 DSM + DSG		**566**
	Difference, 2010 Business Plan less 2008 IRP		**(9)**

Class 2 Demand-side Management

To obtain Class 2 DSM targets, PacifiCorp ran the System Optimizer with a \$45/ton CO_2 allowance price starting point (beginning in 2013) rather than the business plan's original \$8.58/ton price assumption. The resulting Class 2 DSM schedule was then fixed for subsequent portfolio development. The \$45/ton allowance price served as the CO_2 cost assumption for development of the 2008 IRP preferred portfolio. In addition to capturing the long term CO_2 risk mitigation benefits of this resource, its use for business plan DSM target-setting avoids widely fluctuating acquisition amounts relative to the 2008 IRP, which is important for DSM program planning.

The 2010 business plan modeling resulted in nine percent less Class 2 DSM (on a MWh reduction basis) for the 2010-2019 planning period, mostly the result of the revisions to resource supply curves to reflect pending federal lighting code changes, lower load projections, and lower gas/electricity market prices. These factors helped to reduce the availability and need for Class 2 DSM resources within the planning period.

Renewable Resources

For capacity expansion modeling purposes, the Company added a fixed wind acquisition schedule in the portfolio reflecting changes to both the amount and timing of proxy wind projects. These changes resulted in a cumulative wind capacity (or rated capability) decrease of 452 MW for 2009 through 2018, relative to the 2008 IRP preferred portfolio. Other renewable resource options were excluded from the System Optimizer model. The rationale for the modified wind acquisition schedule is provided later in this Chapter.

Front Office Transactions

PacifiCorp relied on the System Optimizer model to select the type, quantity, and timing of front office transactions, subject to the annual capacity limits documented in Table 4.2. Note that the Company will continue to evaluate cost-effective renewable or thermal plant assets as resource alternatives to front office transactions.

Combined Heat and Power

Combined heat and power (CHP) resources were excluded from the business plan portfolio modeling. This decision reflects the expected difficulty in acquiring the capacity indicated in the 2008 IRP preferred portfolio given the very limited opportunities so far presented to the Company. The Company's expectation is that if CHP is to materialize it will develop as a qualified facility and be incorporated into the plan at the state specific avoided cost

BUSINESS PLAN PORTFOLIO

Table 5.3 summarizes the annual megawatt capacity and timing of resources in the 2010 business plan portfolio. (Note that the Top of the World PPA wind project, 200.2 MW, has a commercial on-line date of December 31, 2010, but is shown in 2011, since that is the year that it is available to serve peak loads.) A more detailed table of portfolio resources is provided in Appendix A. Table 5.4 presents the 2008 IRP preferred portfolio, while Table 5.5 shows the resource capacity and timing differences between the 2010 business plan and 2008 IRP portfolios. An explanation of the significant resource changes with respect to the 2008 IRP follows.

Table 5.3 – 2010 Business Plan Portfolio

		Capacity, MW											Cumulative
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total (2010-19)**
East													
	CCCT F 2x1, Utah (North 2015, South 2018)	-	-	-	-	-	-	607	-	-	536	-	**1,143**
	East PPA	-	-	-	200	-	-	-	-	-	-	-	**200**
	Coal & Gas Capacity Upgrades	2	16	20		2		11	37	-	-	-	**86**
	Wind *	128	227	200	-	-	-	-	-	160	100	200	**887**
	DSM, Class 1, Utah Cool Keeper Load Control	-	18	6	5	-	-	-	-	-	-	-	**28**
	DSM, Class 1, Other **	-	25	5	15	20	10	3	-	-	-	-	**78**
	DSM Class 2	56	65	65	66	68	68	49	50	51	50	53	**585**
	Front Office Transaction - 3Qtr HLH	75	-	-	200	338	519	300	300	350	347	350	
West													
	Coal Plant Turbine Upgrades	-	4	-	-	-			12	12	8	12	**48**
	Wind	75	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Other **	-	-	5	17	18	5	-	-	-	-	-	**45**
	DSM Class 2	39	40	40	39	40	40	37	37	27	27	27	**353**
	Solar Photovoltaic (utility-scale)	-	-	1.8	1.8	1.8	1.8	1.8	-	-	-	-	**8.8**
	Front Office Transaction-3Qtr HLH	-	-	-	404	594	704	494	623	608	289	444	
	Annual Additions, Long Term Resources	**299**	**394**	**342**	**344**	**149**	**125**	**708**	**136**	**251**	**721**	**292**	
	Annual Additions, Short Term Resources	**75**	**-**	**-**	**604**	**932**	**1,223**	**794**	**923**	**958**	**636**	**794**	
	Total Annual Additions	**374**	**394**	**342**	**948**	**1,081**	**1,348**	**1,503**	**1,059**	**1,208**	**1,357**	**1,087**	

* Other Class 1 DSM consists of (1) irrigation and residential air conditioning control, and (2) commercial curtailment, including customer-owned standby generation.

Table 5.4 – 2008 IRP Preferred Portfolio

		Capacity, MW											Cumulative
	Resource	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total (2009-18)**
East													
	CCCT F 2x1, (Utah North 2014)	-	-	-	-	-	570	-	-	-	-	-	**570**
	East PPA	-	-	-	200	-	-	-	-	-	-	-	**200**
	Coal & Gas Capacity Upgrades	3	44	33	25	2	14	-	8	-	-	-	**128**
	Blundell Geothermal 3	-	-	-	-	35	-	-	-	-	-	-	**35**
	Wind	99	249	-	100	100	100	150	100	100	50	200	**1,048**
	CHP	2	2	2	3	3	3	4	4	4	4	2	**30**
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	-	**38**
	DSM, Class 1, Utah Cool Keeper Load Control	25	50	40	30	10	10	10	10	10	10	-	**205**
	DSM, Class 1, Other	*	*	*	*	*	*	*	*	*	*	-	**Up to 90**
	DSM Class 2	42	51	49	52	55	55	56	56	58	59	58	**532**
	Front Office Transaction - 3Qtr HLH	75	50	150	394	493	200	202	228	717	800	800	
West													
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	-	**42**
	Swift Hydro Upgrades	-	-	-	25	25	25	-	-	-	-	-	**75**
	Wind	45	20	200	-	-	-	-	-	-	-	-	**265**
	CHP	1	1	1	1	2	2	2	2	2	2	1	**16**
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	-	**12**
	DSM, Class 1	*	*	*	*	*	*	*	*	*	*	-	**Up to 30**
	DSM Class 2	35	36	39	39	38	39	39	39	39	29	29	**372**
	Front Office Transaction-3Qtr / Flat Annual	-	-	59	839	839	739	739	689	289	582	721	
	Annual Additions, Long Term Resources	**257**	**467**	**378**	**491**	**286**	**823**	**266**	**485**	**218**	**158**	**289**	
	Annual Additions, Short Term Resources	**75**	**50**	**209**	**1,234**	**1,332**	**939**	**942**	**918**	**1,006**	**1,382**	**1,521**	
	Total Annual Additions	**332**	**517**	**587**	**1,724**	**1,618**	**1,762**	**1,208**	**1,402**	**1,224**	**1,540**	**1,811**	

Table 5.5 – Resource Differences, 2010 Business Plan Less 2008 IRP Preferred Portfolio

		Capacity, MW											Cumulative
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total (2010-18)
East													
	CCCT F 2x1, Utah	-	-	-	-	-	(570)	607	-	-	536	-	573
	IC Aero SCCT	-	-	-	-	-	-	-	(261)	-	-	-	(261)
	East PPA	-	-	-	-	-	-	-	-	-	-	-	-
	Coal & Gas Capacity Upgrades	(2)	(28)	(13)	(25)	-	(14)	11	29	-	-	-	(39)
	Blundell Geothermal 3	-	-	-	-	(35)	-	-	-	-	-	-	(35)
	Wind	29	(23)	200	(100)	(100)	(100)	(150)	(100)	60	50	-	(262)
	CHP	(2)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(4)	(4)	(2)	(28)
	Distributed Standby Generation	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	-	(35)
	DSM, Class 1, Utah Cool Keeper Load Control	(25)	(33)	(35)	(25)	(10)	(10)	(10)	(10)	(10)	(10)	-	(152)
	DSM, Class 1, Other *	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(13)
	DSM Class 2	14	15	16	14	13	13	(7)	(6)	(6)	(9)	(5)	42
	Front Office Transaction - 3Qtr HLH	-	(50)	(150)	(194)	(154)	319	98	72	(367)	(453)	(450)	
West		-	-	-	-	-	-	-	-	-	-	-	
	Coal Plant Turbine Upgrades	-	(5)	(9)	(12)	(12)	-	-	12	12	8	12	(6)
	Swift Hydro Upgrades	-	-	-	(25)	(25)	(25)	-	-	-	-	-	(75)
	Wind	30	(20)	(200)	-	-	-	-	-	-	-	-	(220)
	CHP	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(1)	(15)
	Distributed Standby Generation	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	-	(11)
	DSM, Class 1, Other *	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	15
	DSM Class 2	3	3	1	0	2	1	(2)	(2)	(12)	(2)	(1)	(11)
	Solar Photovoltaic (utility-scale)	-	-	1.8	1.8	1.8	1.8	1.8	-	-	-	-	8.8
	Front Office Transaction-3 Qtr HLH / Flat Annual	-	-	(59)	(435)	(245)	(35)	(245)	(67)	319	(292)	(277)	
	Annual Additions, Long Term Resources	**41**	**(74)**	**(36)**	**(147)**	**(137)**	**(698)**	**442**	**(348)**	**33**	**563**	**3**	
	Annual Additions, Short Term Resources	**-**	**(50)**	**(209)**	**(630)**	**(400)**	**284**	**(147)**	**5**	**(48)**	**(745)**	**(727)**	
	Total Annual Additions	**41**	**(124)**	**(245)**	**(777)**	**(536)**	**(414)**	**295**	**(343)**	**(15)**	**(183)**	**(724)**	

* The 2008 IRP Preferred Portfolio table cited a range of "up to 120 MW" for other Class 1 DSM (90 MW east, 30 MW west), and excluded customer-owned standby generation. A resource difference is only reported for the 2009-2018 cumulative amounts assuming that the upper east-side and west-side maximums are reached by 2018.

As noted in earlier in this Chapter, revised assumptions regarding Utah transmission import capability from Nevada, as well as lower load growth, supported the deferral of the east-side gas resources. The first gas resource, a CCCT, was deferred from 2014 to 2015. The intercooled aero SCCT, originally appearing in 2016, has now been replaced by a CCCT added in 2018.

There were a number of operational and business planning developments in the 10 months subsequent to the filing of the 2008 IRP that impacted the Company's plans for relatively level wind acquisitions on an annual basis throughout the 10-year investment planning period. Chapter 2 cites the Windstar to Populus Energy Gateway in-service date adjustment and economic downturn. These planning developments prompted the Company to defer wind resource acquisition during the 2012-2016 timeframe.[11] The Company has also gained operational experience with large-scale and rapid wind penetration on portions of the Wyoming system, and consequently continues to focus on maintaining system reliability and efficient use of new and existing resources in the plan.

[11] See page 240 of the 2008 IRP for a discussion on the rationale for distributing wind acquisitions across all years.

Relative to the 2008 IRP preferred portfolio, the wind portfolio is reduced by 550 MW from 2012 through 2016, and a total of 452 MW for 2009 through 2018. Nevertheless, the Company has exceeded the commitment made by MidAmerican Energy Holdings Company and PacifiCorp to have 1,400 MW of cost-effective renewable resources in PacifiCorp's portfolio by 2015; with resources acquired after 2003, PacifiCorp is expected to surpass this commitment by 333 MW by the end of 2010. With the revised wind portfolio and availability of flexible compliance mechanisms, PacifiCorp is expected to meet state and potential federal renewable portfolio standard requirements through this time frame with no new additions as shown later in this section. As noted in Chapter 2, the Company will continue to seek attractive wind and other renewable resource opportunities in light of continuing changes in the economic and regulatory environments.

Table 5.6 shows the capacity Load and Resource balance resulting from the addition of the 2010 business plan portfolio. Note that the renewable resource additions reflect the capacity contribution of wind projects to system coincident peak and not the nominal capacity values shown in the portfolio tables above. Similarly, Class 2 DSM resource additions are reported as the capacity available at the time of the system coincident peak load hour, which is less than the installed capacity reported in Tables 5.3 through 5.5.

Table 5.6 – Portfolio Load and Resource Balance with Additions (Megawatts)

Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
East										
Thermal	5,989	6,009	6,009	6,011	6,011	6,022	6,059	6,059	6,059	6,059
Hydroelectric	132	132	132	132	132	132	132	132	132	132
Class 1 DSM	458	463	468	468	468	468	468	468	468	468
Renewable	157	157	157	157	157	154	154	154	154	154
Purchase	560	655	705	604	304	304	283	283	283	283
Qualifying Facilities	152	152	152	152	152	152	152	152	152	152
Interruptible	327	327	327	327	327	327	327	327	327	327
Transfers	504	751	550	799	830	684	881	868	479	623
East Existing Resources	**8,279**	**8,646**	**8,500**	**8,650**	**8,381**	**8,244**	**8,456**	**8,443**	**8,054**	**8,198**
DSM, Class 1	0	5	20	40	50	53	53	53	53	53
DSM, Class 2	94	143	192	243	295	331	368	406	442	481
Front Office Transactions	0	0	200	338	519	300	300	350	347	350
Gas	0	0	200	200	200	807	807	807	1,343	1,343
Wind	15	20	20	20	20	20	20	24	26	31
East Planned Resources	**109**	**168**	**633**	**842**	**1,084**	**1,511**	**1,548**	**1,639**	**2,211**	**2,258**
East Total Resources	**8,388**	**8,814**	**9,132**	**9,492**	**9,465**	**9,754**	**10,004**	**10,083**	**10,265**	**10,456**
Load	6,753	7,036	7,292	7,577	7,846	8,070	8,295	8,461	8,628	8,804
Sale	768	758	997	1,045	745	745	745	659	659	659
East Obligation	**7,521**	**7,794**	**8,289**	**8,622**	**8,591**	**8,815**	**9,040**	**9,120**	**9,287**	**9,463**
Planning Reserves (12%)	730	744	765	792	795	844	869	868	884	900
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	**800**	**815**	**836**	**863**	**866**	**914**	**939**	**938**	**954**	**971**
East Obligation + Reserves	**8,321**	**8,608**	**9,124**	**9,485**	**9,457**	**9,729**	**9,979**	**10,059**	**10,242**	**10,434**
East Position	**67**	**206**	**8**	**7**	**8**	**25**	**25**	**24**	**24**	**23**
East Reserve Margin	**13%**	**15%**	**12%**	**12%**	**12%**	**12%**	**12%**	**12%**	**12%**	**12%**
West										
Thermal	2,554	2,554	2,554	2,554	2,554	2,554	2,566	2,564	2,572	2,584
Hydroelectric	1,128	1,135	977	976	976	982	982	982	978	925
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Renewable	77	77	71	71	71	71	71	71	71	71
Purchase	1,297	856	247	281	226	221	225	255	269	285
Qualifying Facilities	144	138	135	135	135	135	135	135	135	135
Transfers	(506)	(751)	(551)	(800)	(830)	(684)	(881)	(866)	(479)	(624)
West Existing Resources	**4,694**	**4,009**	**3,433**	**3,217**	**3,132**	**3,278**	**3,097**	**3,140**	**3,546**	**3,375**
DSM, Class 1	0	5	22	40	45	45	45	45	45	45
DSM, Class 2	50	76	101	126	151	175	200	217	234	251
Front Office Transactions	0	0	404	594	704	494	623	608	289	444
Solar	0	1	1	2	3	3	3	3	3	3
West Planned Resources	**50**	**81**	**528**	**762**	**903**	**718**	**871**	**873**	**571**	**744**
West Total Resources	**4,745**	**4,090**	**3,961**	**3,979**	**4,035**	**3,996**	**3,968**	**4,013**	**4,117**	**4,119**
Load	3,166	3,236	3,355	3,400	3,459	3,504	3,546	3,588	3,653	3,674
Sale	490	290	258	258	258	158	108	108	108	108
West Obligation	**3,656**	**3,526**	**3,613**	**3,658**	**3,717**	**3,662**	**3,654**	**3,696**	**3,761**	**3,782**
Planning Reserves (12%)	277	311	341	314	311	327	307	309	351	331
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	**284**	**317**	**347**	**321**	**317**	**334**	**314**	**315**	**357**	**337**
West Obligation + Reserves	**3,933**	**3,836**	**3,954**	**3,972**	**4,028**	**3,989**	**3,961**	**4,004**	**4,112**	**4,113**
West Position	**812**	**253**	**7**	**7**	**7**	**7**	**6**	**8**	**6**	**6**
West Reserve Margin	**34%**	**19%**	**12%**	**12%**	**12%**	**12%**	**12%**	**12%**	**12%**	**12%**
System										
Total Resources	**13,132**	**12,904**	**13,093**	**13,471**	**13,500**	**13,750**	**13,972**	**14,095**	**14,383**	**14,575**
Obligation	**11,176**	**11,319**	**11,902**	**12,280**	**12,308**	**12,477**	**12,694**	**12,816**	**13,048**	**13,245**
Reserves	**1,084**	**1,132**	**1,183**	**1,183**	**1,183**	**1,248**	**1,253**	**1,254**	**1,312**	**1,308**
Obligation + Reserves	**12,260**	**12,451**	**13,085**	**13,463**	**13,491**	**13,725**	**13,947**	**14,069**	**14,360**	**14,553**
System Position	**872**	**453**	**9**	**8**	**9**	**26**	**24**	**26**	**23**	**23**
Reserve Margin	**20%**	**16%**	**12%**	**12%**	**12%**	**12%**	**12%**	**12%**	**12%**	**12%**

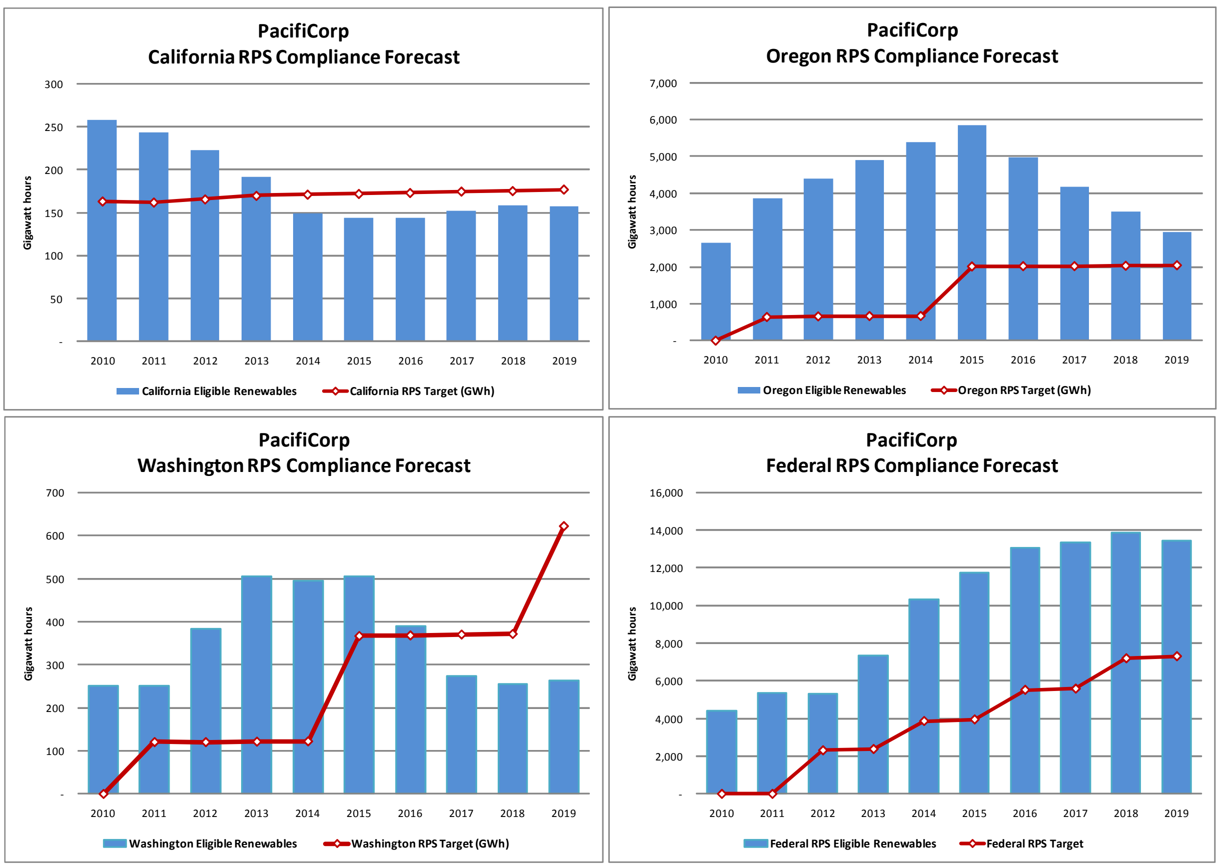
Table 5.7 – Differences: Load and Resource Balance 2008 IRP versus 2008 IRP Update (Megawatts)

Calendar Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
East										
Thermal	(9)	(15)	(57)	(55)	(67)	(56)	(27)	(29)	196	195
Hydroelectric	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Class 1 DSM	63	28	3	(7)	(17)	(27)	(37)	(47)	(57)	(57)
Renewable	0	0	0	0	0	0	0	0	0	0
Purchase	13	113	363	263	(37)	(37)	(37)	(37)	(37)	(37)
Qualifying Facilities	1	1	1	1	1	1	1	1	1	1
Interruptible	90	90	90	90	90	90	90	90	90	90
Transfers	(410)	(43)	(135)	62	265	(85)	144	637	(40)	(9)
East Existing Resources	**(256)**	**170**	**262**	**350**	**232**	**(118)**	**130**	**612**	**150**	**179**
Combined Heat and Power	(4)	(6)	(9)	(11)	(14)	(18)	(22)	(26)	(30)	(32)
Distributed Standby Generation	(8)	(12)	(15)	(19)	(23)	(27)	(31)	(35)	(38)	(38)
DSM, Class 1	0	5	20	40	50	53	53	53	53	53
DSM, Class 2	15	24	32	39	46	37	30	22	11	4
Front Office Transactions	(50)	(150)	(194)	(154)	319	98	72	(367)	(453)	(450)
Gas	0	0	0	0	(570)	37	(224)	(224)	312	312
Geothermal	0	0	0	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Wind	3	8	5	3	1	(3)	(5)	(4)	(3)	(3)
East Planned Resources	**(44)**	**(131)**	**(161)**	**(138)**	**(226)**	**142**	**(163)**	**(616)**	**(183)**	**(190)**
East Total Resources	**(299)**	**40**	**100**	**213**	**6**	**24**	**(32)**	**(3)**	**(34)**	**(10)**
Load	(196)	(114)	(112)	(66)	67	41	(8)	(30)	(68)	(47)
Sale	0	0	250	300	0	0	0	0	0	0
East Obligation	**(196)**	**(114)**	**138**	**234**	**67**	**41**	**(8)**	**(30)**	**(68)**	**(47)**
Planning Reserves (12%)	(39)	(27)	(21)	(4)	(46)	(21)	(21)	31	39	42
Non-owned reserves	0	0	0	0	0	0	0	0	0	0
East Reserves	**(39)**	**(27)**	**(21)**	**(4)**	**(46)**	**(21)**	**(21)**	**31**	**39**	**42**
East Obligation + Reserves	**(235)**	**(141)**	**117**	**230**	**21**	**20**	**(29)**	**1**	**(29)**	**(5)**
East Position	**(64)**	**181**	**(16)**	**(17)**	**(15)**	**4**	**(3)**	**(4)**	**(5)**	**(5)**
East Reserve Margin	**-0.8%**	**2.3%**	**-0.2%**	**-0.2%**	**-0.2%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**-0.1%**
West										
Thermal	(5)	(14)	(25)	(37)	(37)	(37)	(25)	(13)	(5)	7
Hydroelectric	(89)	(81)	(3)	(33)	(70)	(176)	(168)	(167)	(168)	(174)
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Renewable	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)
Purchase	94	103	132	137	115	110	114	144	130	156
Qualifying Facilities	24	18	15	15	15	15	15	15	15	15
Transfers	408	44	135	(62)	(265)	85	(144)	(635)	41	8
West Existing Resources	**413**	**51**	**235**	**1**	**(261)**	**(22)**	**(227)**	**(675)**	**(6)**	**(7)**
Combined Heat and Power	(2)	(4)	(5)	(7)	(9)	(10)	(12)	(14)	(16)	(17)
Distributed Standby Generation	(2)	(4)	(5)	(6)	(7)	(8)	(9)	(11)	(12)	(12)
DSM, Class 1	0	5	22	40	45	45	45	45	45	45
DSM, Class 2	(4)	(7)	(11)	(14)	(18)	(23)	(29)	(41)	(45)	(48)
Front Office Transactions	0	(59)	(435)	(245)	(35)	(245)	(67)	319	(292)	(277)
Solar	0	1	1	2	3	3	3	3	3	3
Wind	0	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
West Planned Resources	**(8)**	**(76)**	**(441)**	**(238)**	**(29)**	**(247)**	**(77)**	**293**	**(325)**	**(314)**
West Total Resources	**405**	**(25)**	**(206)**	**(238)**	**(290)**	**(269)**	**(304)**	**(382)**	**(330)**	**(321)**
Load	(256)	(254)	(232)	(238)	(263)	(265)	(278)	(305)	(325)	(313)
Sale	0	0	0	0	0	0	0	0	0	0
West Obligation	**(256)**	**(254)**	**(232)**	**(238)**	**(263)**	**(265)**	**(278)**	**(305)**	**(325)**	**(313)**
Planning Reserves (12%)	(42)	(36)	7	(19)	(44)	(18)	(41)	(93)	(20)	(23)
Non-owned reserves	0	0	0	0	0	0	0	0	0	0
West Reserves	**(42)**	**(36)**	**7**	**(19)**	**(44)**	**(18)**	**(41)**	**(93)**	**(20)**	**(23)**
West Obligation + Reserves	**(298)**	**(290)**	**(225)**	**(257)**	**(307)**	**(283)**	**(319)**	**(398)**	**(345)**	**(336)**
West Position	**702**	**265**	**19**	**19**	**17**	**14**	**15**	**16**	**14**	**14**
West Reserve Margin	**19.4%**	**7.5%**	**0.5%**	**0.5%**	**0.4%**	**0.4%**	**0.4%**	**0.4%**	**0.3%**	**0.4%**
System										
Total Resources	**105**	**15**	**(105)**	**(25)**	**(284)**	**(245)**	**(337)**	**(385)**	**(364)**	**(332)**
Obligation	**(452)**	**(368)**	**(94)**	**(4)**	**(196)**	**(224)**	**(286)**	**(335)**	**(393)**	**(360)**
Reserves	**(81)**	**(62)**	**(14)**	**(23)**	**(90)**	**(39)**	**(62)**	**(62)**	**19**	**19**
Obligation + Reserves	**(533)**	**(430)**	**(108)**	**(27)**	**(286)**	**(263)**	**(348)**	**(397)**	**(374)**	**(341)**
System Position	**638**	**445**	**3**	**2**	**2**	**18**	**12**	**11**	**10**	**9**
Reserve Margin	**5.8%**	**3.9%**	**0.0%**	**0.0%**	**0.0%**	**0.1%**	**0.1%**	**0.1%**	**0.1%**	**0.1%**

Compliance with Renewable Portfolio Standard Requirements

Figures 5.1 show the forecasted annual RPS compliance positions for the Oregon, Washington, California, and Federal[12] RPS programs, covering the period 2010 through 2019. Utah's RPS goal is tied to a 2025 compliance date, so the 2010-2019 position is not shown below. However, a Utah REC banking balance is assumed to accrue to meet cost-effective clean energy requirements by the 2025 compliance date.

Figure 5.1 – Annual State and Federal RPS position Forecasts



For California and Washington, PacifiCorp expects to utilize flexible compliance mechanisms such a banking, earmarking, and tradable RECs where allowed, to meet the RPS requirements.

[12] The forecasted federal RPS position is a scenario based on RPS provisions of the Waxman-Markey "American Clean Energy and Security Act" (H.R. 2454).

6. Action Plan Update

This section provides the updated IRP Action Plan, modified as a result of the outcome of PacifiCorp's 2010 business planning process. The Action Plan update is presented as Table 6.1. Changes to the original 2008 IRP Action Plan have been highlighted with the use of red font, underlining for additions, and strike-though for deletions. A comments column has also been added to provide background on the action item changes.

Table 6.1 – IRP Action Plan Update

Action items anticipated to extend beyond the next two years, or occur after the next two years, are indicated in italics.

<table>
<tr><th>Action Item</th><th>Category</th><th>Timing</th><th>Action(s)</th><th>Change Comments</th></tr>
<tr><td>1</td><td>Renewables</td><td>2010 - 2019
~~2009 - 2018~~</td><td>Acquire an incremental 890 ~~1,400~~ MW of renewable resource by 2019. ~~2018, in addition to the already planned 75 MW of major hydroelectric upgrades in 2012-2014; PacifiCorp's projected renewable resource inventory exceeds 2,540 MW with these resource additions~~
• ~~Successfully add 144 MW of wind resources in 2009 that are currently in the project pipeline, including PacifiCorp's 99 MW High Plains facility in Wyoming, and 45 MW of power purchase agreement capacity~~
• Successfully add 230 ~~269~~ MW of wind resources in 2010 and 200 MW of wind resources in 2011 that are currently committed to.~~, including 119 MW of power purchase agreement capacity already contracted~~
• ~~Procure up to an additional 500 MW of cost-effective renewable resources for commercial operation, subject to transmission availability, starting in the 2009 to 2011 time frame under the currently active renewable resource RFP (2008R-1) and the next renewable resource RFP (2009R) expected to be issued in the second quarter of 2009~~
– ~~The Company is expected to submit company resources (self build or ownership transfers) in the 2009R RFP~~
• *Procure up to an additional 460 MW ~~500 MW~~ of cost-effective wind resources for commercial operation, subject to transmission availability~~, starting~~ in the 2017 to 2019 ~~2012 to 2018~~ time frame via RFPs or other opportunities*
– *~~Procure at least 35 MW of viable and cost-effective geothermal or other base-load renewables~~*
• *Monitor geothermal, solar and emerging technologies, and*</td><td>• PacifiCorp exceeded its 2009-2010 wind acquisition goals: total acquisition stands at 430 MW vs. 413 MW identified in the 2008 IRP action plan
• PacifiCorp is meeting the 200 MW wind acquisition goal for 2011 via the 200.2 MW Top of the World PPA, obtained through the 2008R-1 renewables RFP
• Deferred/postponed wind resources (post-2011) reflect a reassessment of transmission availability, lower forecasted load growth, and capital budget reductions</td></tr>
</table>

Action Item	Category	Timing	Action(s)	Change Comments
			government financial incentives; ~~and~~ procure geothermal, solar or other cost-effective renewable resources during the 10-year investment horizon. • *Continue to evaluate the prospects and impacts of Renewable Portfolio Standard rules and CO_2 emission regulations at the state and federal levels, and adjust the renewable acquisition timeline accordingly.*	
2	**Firm Market Purchases**	**2010 - 2019** **~~2009 - 2013~~**	Implement a bridging strategy to support acquisition deferral of long-term intermediate/base-load resource(s) in the east control area until the beginning of summer 2015, unless cost-effective long-term resources such as renewable or thermal plant assets are available and their acquisition is in the best interests of customers. ~~until no sooner than the beginning of summer 2014~~ • Acquire the following resources: – Up to 1,250 MW ~~1,400 MW~~ of economic front office transactions on an annual basis as needed through 2015 ~~2013~~, taking advantage of favorable market conditions – At least 200 MW of long-term power purchases – Cost-effective interruptible customer load contract opportunities (focus on opportunities in Utah) – PURPA Qualifying Facility contracts and cost-effective distributed generation alternatives (Customer-owned standby generation is addressed in Action Item no. 5) • Resources will be procured through multiple means: (1) the All-Source RFP reissued on December 2, 2009 ~~reactivation of the suspended 2008 the All-Source RFP in Dec 2009~~, which seeks third quarter summer products and customer physical curtailment contracts among other resource types, (2) periodic mini-RFPs that seek resources less than five years in term, and (3) bilateral negotiations.	The reduction in the maximum expected quantity of firm market purchases reflects lower expected load growth.

Action Item	Category	Timing	Action(s)	Change Comments
			• Closely monitor the near-term need for front office transactions and reduce acquisitions as appropriate if load forecasts indicate recessionary impacts greater than assumed for the February 2009 load forecast, or if renewable or thermal plant assets are determined to be cost-effective alternatives. • Acquire incremental transmission through Transmission Service Requests to support resource acquisition.	
3	**Peaking / Intermediate / Base-load Supply-side Resources**	**2014 ~~2012~~ - 2016**	Procure through acquisition and/or company construction, long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame • The proxy resource included in the 2010 business plan portfolio consists of a Utah wet-cooled gas combined-cycle plant with a capacity rating of 607 MW, acquired by the summer of 2015 ~~The proxy resources included in the preferred portfolio consist of (1) a Utah wet-cooled gas combined-cycle plant with a summer capacity rating of 570 MW, acquired by the summer of 2014, and (2) a 261 MW east-side intercooled aeroderivative simple-cycle gas plant acquired by the summer of 2016~~ • Procure through ~~activation of~~ the ~~suspended~~ 2008 all-source RFP issued in ~~late~~ December 2009 – The Company ~~plans to~~ submitted a benchmark ~~Company~~ resource~~s~~, specified as the addition of a second combined cycle block at PacifiCorp's Lake Side Plant. ~~(self-build or ownership transfers) once the suspension is removed~~ • *In recognition of the unsettled U.S. economy, expected continued volatility in natural gas markets, and regulatory uncertainty, continue to seek cost-effective resource deferral and acquisition opportunities in line with near-term updates to load/price forecasts, market conditions, transmission plans, and regulatory developments.*	• Deferral of the 2014 combined-cycle plant resource to 2015 reflects lower load growth expectations than assumed for the 2008 IRP; bid evaluation for the all-source RFP will use the October 2009 load forecast to determine the revised portfolio capacity and energy requirements • The change to the last bullet in this action item reflects modifications agreed to by the Company as part of the 2008 IRP acknowledgment process in Oregon. This 2008 IRP Update report demonstrates compliance with this action item change.

Action Item	Category	Timing	Action(s)	Change Comments
			PacifiCorp will reexamine the timing and type of gas resources and other resource changes as part of a comprehensive assumptions update and portfolio analysis to be conducted for the 2008 RFP final short-list evaluation in the RFP approved in Docket UM 1360, the next business plan, and the 2008 IRP update.	
4	Plant Efficiency Improvements	2010 - 2019 ~~2009 -2018~~	Pursue economic plant upgrade projects—such as turbine system improvements and retrofits—and unit availability improvements to lower operating costs and help meet the Company's future CO_2 and other environmental compliance requirements. • *Successfully complete the dense-pack coal plant turbine upgrade projects by 2019 ~~2016~~, which are expected to add 86 MW ~~128 MW~~ of incremental capacity in the east and 48 MW ~~42 MW~~ in the West with zero incremental emissions.* • *Seek to meet the Company's aggregate coal plant net heat rate improvement goal of 213 Btu/kWh by 2018[13].* • *Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules.*	Capital budget reductions impacted the dense-pack upgrade project timeline, resulting in capacity reductions and project deferrals.
5	Class 1 DSM	2010 - 2019 ~~2009 -2018~~	Acquire up to 200 MW ~~at least 200 – 300 MW~~ of cost-effective Class 1 demand-side management programs for implementation in the 2010-2019 ~~2009-2018~~ time frame • *Pursue up to 30 MW ~~200 MW~~ of expanded Utah Cool Keeper program participation by 2019 ~~2018~~;* revisit the program's growth assumptions in light of the recent passage of Utah legislation that permits an opt-out program design. • *Pursue up to 100 MW ~~130 MW~~ of additional cost-effective class 1 DSM products including commercial curtailment and customer-owned standby generation (55 MW ~~90 MW~~ in the east side and 45*	2008 RFP proposals provided opportunity for up to 100 MW of new class 1 DSM products for Company consideration, provided they are found to be cost-effective, vendor agreements can be negotiated, and state commissions are supportive and approve the programs

13 *PacifiCorp Energy Heat Rate Improvement Plan*, March 31, 2009.

Action Item	Category	Timing	Action(s)	Change Comments
			MW ~~30 MW~~ in the west side) to hedge against the risk of higher gas prices and a faster-than-expected rebound in load growth resulting from economic recovery; procure through the currently active 2008 DSM RFP and subsequent DSM RFPs. • For ~~2009~~ 2010, continue to implement a standardized Class 1 DSM system benefit estimation methodology for products modeled in the IRP. The modeling will compliment the supply curve work by providing additional resource value information to be used to evolve current Class 1 products and evaluate new products with similar operational characteristics that may be identified between plans.	and associated cost recovery.
6	Class 2 DSM	2010 - 2019 ~~2009 -2018~~	Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2019, ~~2018~~ equivalent to about 4.1 to 4.6 million MWh. • *Procure through the currently active DSM RFP and subsequent DSM RFPs*	• The DSM RFP produced several proposals that are being considered. Additional analysis, contracting, and regulatory approvals are required before new programs can be introduced. • Subsequent to the 2010 business plan modeling and in compliance with Washington I-937 requirements the company filed a ten-year conservation forecast in Washington. The filing made in January, 2010 increased the company's Washington class 2 forecast 42% from the 2008

Action Item	Category	Timing	Action(s)	Change Comments
				IRP resource forecast of 34.7 MWa and 51% from the adjusted 2010 business plan target in Washington. In addition, the company extended the SB838 enabled conservation funding to the Energy Trust of Oregon necessary for the pursuit of class 2 resources in Oregon consistent with the 2008 IRP forecast.
7	Class 3 DSM	2010 - 2019 ~~2009 -2018~~	Acquire cost-effective Class 3 DSM programs by 2018 • *Procure programs through the currently active DSM RFP and subsequent DSM RFPs.* • *Continue to evaluate program attributes, size/diversity, and customer behavior profiles to determine the extent that such programs provide a sufficiently reliable firm resource for long-term planning.* • *Portfolio analysis with Class 3 DSM programs included as resource options indicated that at least 100 MW may be cost-effective; continue to evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling*	Class 3 DSM potential is being revisited as part of the 2010 update of the 2007 DSM Potential Assessment study. Class 3 DSM products continue to be a challenge to pursue effectively, mostly due to their voluntary nature and utility rate design risks associated with recovery of fixed costs.
~~8~~	~~Distributed Generation~~	~~2009 -2018~~	~~Pursue at least 100 MW of distributed generation resources by 2018~~ • ~~*Procure at least 50 MW of combined heat and power (CHP) generation: 30 MW for the east side and 20 MW for the west side, to include purchase of facility output pursuant to PURPA regulations supply-side RFPs (renewable shelf RFPs and All Source RFPs, which provide for QFs with a capacity of 10 MW*~~	Distributed generation is now covered under Action Item nos. 2 and 5.

Action Item	Category	Timing	Action(s)	Change Comments
			~~or greater), and other opportunities; focus on renewable fuel and other "clean" facilities to the extent that federal and state Renewable Production Tax credit rules provide additional Renewable Energy Credit value to such facilities~~ • ~~Procure at least 50 MW of cost-effective customer standby generation: 38 MW for the east side (subject to air permitting restrictions and other implementation constraints) and 12 MW for the west side. Procurement to be handled by competitive RFP for demand response network service and/or individual customer agreements~~ • ~~Seek up to an additional 40 MW of customer standby generation if the economic recession and market conditions continue to support elimination of simple-cycle gas units or other peaking resources as indicated by IRP portfolio modeling for the 2010 business plan/2008 IRP update~~	
8 ~~9~~	**Planning Process Improvements**	~~2009-~~2010	Portfolio modeling improvements • For the next IRP planning cycle, ~~C~~complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and Renewable Portfolio Standard (RPS) regulatory requirements at the jurisdictional level. Use the enhanced model to provide more detailed analysis of potential hard-cap regulation of carbon dioxide emissions and achievement of state or federal emissions reduction goals. Also use the capacity expansion model to evaluate the cost-effectiveness of coal facility retirement as a potential response to future regulation of carbon dioxide emissions • ~~Continue to improve wind resource modeling by refining the representation of intermittent wind resources; attributes to consider include incremental reserve requirements and other components tied to system integration, geographical diversity~~	• The changes to this action item reflect modifications agreed to as part of the 2008 IRP acknowledgment process in Oregon. • Removal of the second bullet eliminates redundant language due to the addition of new action item #18 (2010 wind integration study).

Action Item	Category	Timing	Action(s)	Change Comments
			~~impacts, and peak load carrying capability estimation~~ • Refine modeling techniques for DSM supply curves/program valuation, and distributed generation • Investigate and implement, if beneficial, the Loss of Load Probability (LOLP) reliability constraint functionality in the System Optimizer capacity expansion model • Continue to coordinate with PacifiCorp's transmission planning department on improving transmission investment analysis using the IRP models • For the next IRP planning cycle, provide an evaluation of, and ~~C~~continue to investigate, ~~the formulation of satisfactory proxy~~ intermediate-term market purchase resources for purposes of portfolio modeling~~, contingent on acquiring suitable market data~~ ~~Establish additional portfolio development scenarios for the business plan that will be completed by the end of 2009, and which will support the 2008 IRP update~~ • ~~A federal CO_2 cap-and-trade policy scenario along the lines originally proposed for this IRP~~ • Consider developing one or more scenarios incorporating plug-in electric vehicles and Smart Grid technologies	
9 ~~10~~	**Transmission**	**2009-2011**	Obtain Certificates of Public Convenience and Necessity and conditional use permits for Utah/Wyoming/Idaho ~~Nevada~~ segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief • Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Mona and Oquirrh • Obtain Certificate of Public Convenience and Necessity for 230	

Action Item	Category	Timing	Action(s)	Change Comments
			kV and 500 kV line between Windstar and Populus • Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Populus and Hemingway	
10 ~~11~~	**Transmission**	**2010**	Complete ~~Permit and build~~ Utah/Idaho~~/Nevada~~ segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. Includes: • ~~Permit c~~Complete construction of a 345 kV line between Populus to Terminal	
11 ~~12~~	**Transmission**	**2013 - 2014** ~~**2012**~~	*Complete permitting~~Permit~~ and construction of the Utah segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. Includes:* • *~~Permit and Construct~~ A 500 kV line between Mona and Limber and a 345kV line from Limber to Oquirrh*	The projected in-service date range reflects experience and revised expectations with siting and permitting the Energy Gateway project.
12 ~~13~~	**Transmission**	**2014 - 2016**	*Complete permitting ~~Permit~~ and ~~Build~~ construction of the Wyoming / Idaho / Utah segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. Includes:* • *~~Permit and construct~~ A 230 kV and 500 kV line between Windstar and Populus* • *~~Permit and construct~~A 345 kV line between Sigurd and Red Butte*	The projected in-service date range reflects experience and revised expectations with siting and permitting the Energy Gateway project.
13 ~~14~~	**Transmission**	**2016 - 2018**	*Complete permitting ~~Permit~~ and ~~build~~ construction of the Idaho ~~Northwest/Utah/Nevada~~ segment~~s~~ of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. Includes:* • *~~Permit and construct~~ A 500 kV line between Populus and Hemingway*	The projected in-service date range reflects experience and revised expectations with siting and permitting the Energy Gateway project.

Action Item	Category	Timing	Action(s)	Change Comments
14 ~~15~~	Transmission	2017 - 2019	*Complete permittingPermit and ~~build~~ construction of the Wyoming/Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, market access, grid reliability, and congestion relief. Includes:* • *~~Permit and construct~~ A 500 kV line between Aeolus and Mona*	The projected in-service date range reflects experience and revised expectations with siting and permitting the Energy Gateway project.
15	Transmission	2010-2011	Obtain rights of way for the Wallula-McNary line segment by the end of 2010, and complete construction by the end of 2011	Added to account for transmission requests received in 2009
16	Transmission	2010-2019	For future IRP planning cycles, include on-going financial analysis with regard to transmission, which includes: a comparison with alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects, the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments and base case segments.	This new action item was agreed to with Oregon commission staff as part of the 2008 IRP acknowledgment process.
17	Renewables	2010	By August 2, 2010, complete a wind integration study that has been vetted by stakeholders through a public participation process.	This new action item was agreed to with Oregon commission staff as part of the 2008 IRP acknowledgment process.
18	Planning Process Improvements	2010	During the next planning cycle, work with parties to investigate carbon dioxide emission levels as a measure for portfolio performance scoring.	This new action item was agreed to with Oregon commission staff as part of the 2008 IRP acknowledgment process.
19	Planning Process Improvements	2010	In the next IRP, provide information on total CO_2 emissions on a year-to-year basis for all portfolios, and specifically, how they compare with the preferred portfolio.	This new action item was agreed to with Oregon commission staff as part of the 2008 IRP

Action Item	Category	Timing	Action(s)	Change Comments
				acknowledgment process.
<u>20</u>	<u>Planning Process Improvements</u>	<u>2010</u>	<u>For the next IRP planning cycle, work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.</u>	This new action item was agreed to with Oregon commission staff as part of the 2008 IRP acknowledgment process.
<u>21</u>	<u>Planning Process Improvements</u>	<u>2010</u>	<u>In the next IRP planning cycle, incorporate assessment of distribution efficiency potential resources for planning purposes.</u>	This new action item was agreed to with Oregon commission staff as part of the 2008 IRP acknowledgment process.

Appendix A – Additional Load Forecast and Resource Portfolio Information

October 2009 Load Forecast

The Load forecast presented in Chapter 3 represents the data used for capacity expansion modeling, and excludes load reductions from energy efficiency resources (Class 2 DSM) included in the 2010 business plan selected by PacifiCorp's capacity expansion model. To arrive at the retail sales forecast, total Class 2 DSM is reduced by an estimated forecast of load reductions from existing DSM programs captured in the historical load data. This adjustment is intended to avoid double counting of incremental DSM. The post-DSM load forecast then captures the energy savings from the incremental DSM. Tables A.1 and A.2 present the "post-DSM" load forecasts—energy and coincident peak loads, respectively, while Table A.3 presents the Class 2 DSM load reductions.

Table A.1 – Post-DSM: Annual Forecasted Loads in Megawatt-hours

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2010	**58,776,967**	13,934,638	4,448,722	933,910	24,015,188	9,962,276	3,283,744	2,198,489
2011	**60,253,204**	14,101,642	4,473,263	954,495	24,568,587	10,245,483	3,683,809	2,225,925
2012	**62,176,645**	14,497,750	4,521,492	978,476	25,496,875	10,681,488	3,747,208	2,253,356
2013	**63,798,306**	14,650,217	4,525,633	986,167	26,343,640	11,153,448	3,858,407	2,280,793
2014	**65,342,382**	14,725,514	4,539,637	991,162	27,116,354	11,643,371	4,018,131	2,308,214
2015	**66,648,048**	14,759,345	4,560,025	997,390	27,785,661	12,160,237	4,049,744	2,335,646
2016	**67,922,111**	14,815,517	4,588,859	1,006,800	28,537,680	12,525,142	4,085,052	2,363,061
2017	**68,663,820**	14,825,635	4,594,573	1,009,979	28,985,615	12,749,691	4,107,829	2,390,500
2018	**69,617,821**	14,901,646	4,627,356	1,020,071	29,515,028	12,990,055	4,145,748	2,417,916
2019	**70,619,033**	15,001,967	4,657,755	1,029,728	30,044,993	13,257,315	4,181,919	2,445,357
Annual Average Growth Rate for 2010-2019								
	2.1%	0.8%	0.5%	1.1%	2.5%	3.2%	2.7%	1.2%

Table A.2 – Post-DSM: Annual Forecasted Coincidental Peak Loads in Megawatts

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2010	**9,773**	2,210	745	151	4,488	1,244	592	342
2011	**10,050**	2,237	754	155	4,590	1,279	683	352
2012	**10,352**	2,290	786	160	4,736	1,324	695	359
2013	**10,602**	2,318	771	163	4,885	1,379	719	368
2014	**10,853**	2,338	781	161	5,012	1,434	750	377
2015	**11,060**	2,345	789	163	5,121	1,491	767	384
2016	**11,265**	2,350	796	165	5,252	1,531	780	391
2017	**11,414**	2,359	803	170	5,341	1,557	786	398

Year	Total	OR	WA	CA	UT	WY	ID	SE ID
2018	**11,591**	2,370	837	169	5,430	1,584	795	406
2019	**11,732**	2,385	821	171	5,523	1,615	804	413
Annual Average Growth Rate for 2010-2019								
	2.1%	0.8%	1.1%	1.4%	2.3%	2.9%	3.4%	2.1%

Table A.3 – Class 2 DSM Megawatt-hours included in Post-DSM Load Forecast, 2010-2019

Year	Total	OR	WA	CA	UT	WY	ID
2010	**831,672**	293,202	61,358	12,971	369,380	61,481	33,278
2011	**1,266,622**	441,432	92,239	19,361	554,352	109,532	49,706
2012	**1,702,581**	589,661	121,222	25,650	740,828	158,791	66,428
2013	**2,147,603**	737,890	152,083	32,009	934,138	208,263	83,220
2014	**2,594,358**	886,120	183,036	38,368	1,128,594	258,199	100,041
2015	**2,956,456**	1,031,744	206,978	43,154	1,261,842	300,254	112,484
2016	**3,327,001**	1,177,369	234,496	47,996	1,398,087	343,800	125,254
2017	**3,649,607**	1,271,596	261,431	52,963	1,537,731	387,628	138,258
2018	**3,971,322**	1,365,823	288,157	57,489	1,676,153	432,308	151,392
2019	**4,300,632**	1,460,051	315,439	62,248	1,820,160	476,773	165,962
Annual Average Growth Rate for 2010-2019							
	20.0%	19.5%	20.0%	19.0%	19.4%	25.6%	19.5%

DETAILED 2010 BUSINESS PLAN PORTFOLIO

Table A.4 presents the detailed listing of resources in the 2010 business plan portfolio. These resources reflect a capacity expansion model run through 2028 in order to show the resource mix impact of adding 800 MW of wind resources to meet an assumed federal RPS requirement by 2025.

Table A.4 – 2010 Business Plan Resource Portfolio (2010-2028)

	Capacity, MW																			Resource Sum Years	
Resource	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**'2010-19**	**'2010-2028**
East																					
CCCT F 2x1, Utah (North 2015, South 2018)	-	-	-	-	-	607	-	-	536	-	-	-	-	-	-	-	-	-	-	1,143	1,143
East PPA	-	-	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201
Coal & Gas Capacity Upgrades	16	20		2		11	37	-	-	-	-	-	-	-	-	-	-	-	-	86	86
Wind, Top of the World (PPA)	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
Wind, McFadden Ridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind, Dunlap 1	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	111	111
Wind, Three Buttes (PPA)	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	99
Wind, Casper (PPA)	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
Wind, High Plains	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind, WYSW, 35% Capacity Factor	-	-	-	-	-	-	-	160	100	200	200	200	200	200	-	-	-	-	-	460	1,260
Total Wind	**227**	**200**	**-**	**-**	**-**	**-**	**-**	**160**	**100**	**200**	**200**	**200**	**200**	**200**	**-**	**-**	**-**	**-**	**-**	**887**	**1,687**
DSM, Class 1, UT-Coolkeeper	18	6	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28	28
DSM, Class 1, Irrigate	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
DSM, Class 1, UT-DLC-RES	-	5	15	15	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
DSM, Class 1, WY-DLC-RES	-	-	-	5	5	3	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1 Total	**43**	**11**	**20**	**20**	**10**	**3**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**106**	**106**
DSM, Class 2, Goshen	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	19	37
DSM, Class 2, Utah	54	54	54	56	57	39	40	41	39	43	43	45	46	43	42	47	48	48	48	477	886
DSM, Class 2, Wyoming	9	9	9	9	10	8	8	8	9	8	9	9	9	10	10	10	10	10	10	89	175
DSM, Class 2 Total	**65**	**65**	**66**	**68**	**68**	**49**	**50**	**51**	**50**	**53**	**54**	**56**	**57**	**55**	**54**	**59**	**60**	**59**	**59**	**585**	**1,098**
FOT Mead, 3rd Qtr HLH	-	-	-	38	219	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
FOT Utah, 3rd Qtr HLH	-	-	-	-	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50		
FOT Mona, 3rd Qtr HLH	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
FOT Mona-3, 3rd Qtr HLH	-	-	-	300	300	300	300	300	297	300	300	300	300	300	300	300	300	300	300		
Growth Resource Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94	277	187	299		
Growth Resource Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7		
West																					
Coal Plant Turbine Upgrades	4	-	-	-			12	12	8	12	-	-	-	-	-	-	-	-	-	48	48
Wind PPA	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
Total Wind	**20**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**20**	**20**
DSM, Class 1, WW-Irrigate	-	0	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, WM-DLC-RES	-	2	8	10	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
DSM, Class 1, WM-Irrigate	-	2	6	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, YA-Irrigate	-	1	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1 Total	**-**	**5**	**17**	**18**	**5**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**45**	**45**
DSM, Class 2, Walla Walla	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	31	56
DSM, Class 2, West Main	30	30	30	30	30	29	29	19	19	19	19	19	19	19	19	19	19	19	19	264	437
DSM, Class 2, Yakima	6	6	6	6	6	5	5	6	5	6	6	6	6	6	6	6	6	6	6	58	111
DSM, Class 2 Total	**40**	**40**	**39**	**40**	**40**	**37**	**37**	**27**	**27**	**27**	**27**	**28**	**28**	**28**	**28**	**28**	**28**	**28**	**28**	**353**	**604**
Solar	-	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-		
FOT COB, 3rd Qtr HLH	-	-	389	389	389	289	239	239	239	239	239	239	239	239	239	239	239	239	239		
FOT Mid-Columbia, 3rd Qtr HLH	-	-	-	155	265	155	333	319	-	155	344	10	311	400	400	400	400	400	400		
FOT West Main, 3rd Qtr HLH	-	-	15	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50		
Growth Resource Walla Walla	-	-	-	-	-	-	-	-	-	-	-	12	13	26	92	175	173	171	167		
Growth Resource West Main	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	259	302		
Growth Resource Yakima	-	-	-	-	-	-	-	-	-	-	-	152	-	14	16	136	144	156	170		
Annual Additions, Long Term Resources	**414**	**342**	**344**	**149**	**125**	**708**	**136**	**251**	**721**	**292**	**282**	**284**	**285**	**283**	**81**	**87**	**87**	**87**	**87**		
Annual Additions, Short Term Resources	**-**	**-**	**604**	**932**	**1,223**	**794**	**923**	**958**	**636**	**794**	**984**	**814**	**963**	**1,080**	**1,147**	**1,444**	**1,633**	**1,813**	**1,984**		
Total Annual Additions	**414**	**342**	**948**	**1,081**	**1,348**	**1,503**	**1,059**	**1,208**	**1,357**	**1,087**	**1,265**	**1,097**	**1,248**	**1,363**	**1,229**	**1,531**	**1,720**	**1,900**	**2,071**		